BEFORE THE PUBLIC SERVICE COMMISSION FOR THE STATE OF DELAWARE

In the Matter of Integrated Resource Planning	:	
For the Provision of Standard Offer of Service	:	
by Delmarva Power & Light Company	:	PSC Docket No. 07-20
Under 26 Del.C. §1007 (c) & (d); Review of	:	
Initial Resource Plan Submitted December 1, 2006	:	
Submitted December 1, 2006	:	
(Opened January 23, 2007)	:	

Delmarva Power & Light Company's Delaware IRP Update

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Delaware IRP Update

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I. Introduction

The Electric Utility Retail Customer Supply Act ("EURSCA" or "HB6") specified that Delmarva Power & Light ("DPL," "Delmarva" or the "Company") file an Integrated Resource Plan ("IRP") on December 1, 2006 and every two years thereafter through 2016. Consequently the next IRP due to be filed under EURCSA is December 1, 2008. Delmarva filed its IRP on December 1, 2006. Pursuant to an agreement with Commission Staff, Delmarva agreed to file an updated IRP; howeverthe EURSCA mandated RFP process was in progress, at the time Delmarva therefore suggested that the IRP be updated following the State Agencies decision regarding the RFP process in order to include the results of that decision.

As the RFP process continued throughout 2007 and no final decision on the RFP process was made, Delmarva requested extensions of time to file the updated IRP. Delmarva's requests were granted, the latest postponing the updated IRP filing date to March 5, 2008.

Many significant events affecting energy planning and Delaware's energy future have occurred since Delmarva's December 1, 2006 filing and this update incorporates those events..

Delmarva believes that the updated IRP outlines a flexible approach to planning Delaware's energy future over a wide range of possible outcomes; it does not attempt to determine a single optimal outcome or solution dependent on rigid or specific forecast assumptions. This IRP update outlines a path forward in several key areas including portfolio management, reliability, and demand response. Integral to the success of the IRP action plan is the timely creation of a collaborative "Portfolio Working Group" whose purpose is to develop the “rules of the road” for Delmarva to implement and operate a Standard Offer Service (“SOS”) resource portfolio.

As this IRP is reviewed by the Delaware Public Service Commission (“DEPSC”or the “Commission”) and presented to the public in the coming months, Delmarva will incorporate feedback received into a more detailed IRP to be filed December 1, 2008 as required by EURCSA. Delmarva also believes that is important for the Commission and other stakeholders to have and understand Delmarva’s updated IRP as early as possible so that we can move forward on the many issues that will determine Delaware’s energy future. Delmarva believes that cooperative participation by all parties and appropriate and timely decision making will greatly facilitate the achievement of reasonable cost, cleaner energy, and stable prices.

It is clear that there is no single “silver bullet” to resolve future electrical supply needs. A balance of renewable resources, transmission enhancements, market resources, energy efficiency and demand response programs must all come together to manage future needs. The ever changing nature of the business is a constant reminder that this plan is only a snapshot in a long-term process.

II. Key Events Occurring After December 1, 2006

Under the requirements of the Electric Utility Retail Customer Supply Act of 2006 and as part of Delaware Public Service Commission's Docket No 06-241, Delmarva filed an Integrated Resource Plan with the Commission on December 1, 2006.[1] It has been Delmarva's intent to update the results of the resource plan and Standard Offer Service procurement strategies as needed upon such time as the Commission and the State Agencies concluded their evaluation of the proposals received as part of the Generation Request for Proposal ("RFP") process. Due to the duration of the RFP process, Delmarva was granted an extension of time by Hearing Examiner Price to prepare and file an updated IRP on March 5, 2008[2].

Since the Company's filing of December 1, 2006 there have been a number of significant events and developments in Delaware regarding Delaware's energy future that affect resource planning and energy procurement. These events include:

- The General Assembly, with support from the Company, passed legislation that essentially doubled the Renewable Portfolio Standard ("RPS") requirements for the procurement of energy from eligible renewable resources and introduced a solar carve out for the State[3].
- The Delaware Public Service Commission Staff ("Staff") filed a Generation Bid Evaluation Report on May 2, 2007. In this report Staff recommended that Delmarva move ahead with a resource portfolio approach for SOS customer

[1] Delmarva Power & Light IRP compliance filing December 1, 2006
[2] See letter dated October 22, 2007 from Hon. Ruth Ann Price
[3] Title 29 Del C. §8059

energy procurement[4]. On May 22, 2007 the Commission issued Order No 7199 in which they adopted Staff's recommendation.[5]

- Staff's May 2, 2007 report presented an evaluation of electric reliability issues in southern Delaware including scenarios of generation unit retirement and recommended that due to potential reliability and price stability benefits the Commission consider the possibility of regulated generation projects as specifically permitted by EURSCA.[6]
- The Office of Management and Budget issued the report "Delaware's Electricity Future: Re-Regulation Options and Impacts" on electric re-regulation options in Delaware in early May.[7] This report was supportive of adopting the portfolio approach for SOS customer energy procurement.
- On February 2, 2007, Delmarva filed with the Commission the application and plan for the Blueprint for the Future ("Blueprint"). This application laid out the Company's vision for the deployment of advanced technology to create a "smart grid" including Advanced Meter Infrastructure ("AMI"), various cost-effective Demand Side Management ("DSM") and Demand Response ("DR") programs, and a revenue decoupling mechanism called a Bill Stabilization Adjustment ("BSA").[8] The Commission opened Docket No. 07-28 for the purpose of investigating the Company's Blueprint filing and also initiated a statewide generic proceeding, Regulation Docket No. 59, to consider whether to implement a

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[4] See Generation bid Evaluation Report, May 2 2007
[5] See Order No 7199 Issues May 22 2007
[6] See Generation Bid Report, dated May 2, 2007 at pgs. 59, 61, 67,68 and 70.
[7] See **Delaware's Electricity Future: ReRegulation Options and Impacts** A Report Pursuant to SS1 of SJR13 of the 143rd General Assembly, May 7, 2007
[8] See Blueprint filing

revenue decoupling mechanism for electric and natural gas utilities in the state. Both proceedings were initiated on March 20, 2007[9].

- The General Assembly passed legislation creating the Sustainable Energy Utility ("SEU") whose purpose, among other things, is to foster the development and implementation of technologically feasible and cost-effective conservation measures and energy efficiency programs throughout the State of Delaware[10].
- On October 17, 2007 an important milestone was achieved for the Mid Atlantic Power Pathway ("MAPP") transmission project as the 500 kV portion of the project was approved by the PJM Board as part of the PJM Regional Transmission Expansion Process ("RTEP") process.[11]
- The third SOS procurement auction since May 2006 was successfully completed in early 2008, resulting in a moderate increase of 1.86% in total bill for Residential customers and a similar size increase for Small Commercial customers ("RSCI") beginning June 1, 2008 (this follows a 2007 increase for the Residential customers of 0.31%).
- Customer shopping statistics indicate that large commercial customers have substantial interest in and ability to shop for their electricity supply requirement. (65% of this load had switched as of January 2008). Residential customers have demonstrated considerably less propensity to migrate away from SOS. (less than 4% of load had switched as of January 2008).

[9] See Orders Nos. 7153 and 7154
[10] 29 Del C. §§8057 and 8059
[11] On November 16, 2007, PJM Interconnection, L.L.C. submitted amendments to Schedule 12-Appendix of the PJM Tariff to reflect cost responsibility assignments for transmission expansion and enhancements, including three baseline upgrades, which were part of the most recent update to the RTEP approved by the PJM Board of Managers on October 17, 2007. This filing lists the MAPP project as one of the RTEP projects which was approved by the PJM Board of Managers on October 17th. Docket No. ER08-229-000.

- The Federal Energy Regulatory Commission ("FERC") authorized PJM's Reliability Pricing Model ("RPM") on Dec 22, 2006[12]. The initial implementation of the 3-year forward capacity market envisioned by RPM required a transition schedule. In 2007, three Base Residual Auctions ("BRA") for the transition period (2007/2008, 2008/2009 and 2009/2010) were conducted for four Locational Deliverability Areas ("LDAs") within PJM. The initial RPM capacity auction took place in April 2007 and the resulting capacity prices were effective June 1, 2007. The applicable locational capacity price for the PJM DPL zone was $197 per MW day for the 2007/2008 delivery year. Subsequent Base Residual Auctions have taken place for the periods beginning June 1, 2008, June 1, 2009 and June 1, 2010. The resulting capacity prices for Delaware loads are: $148 per MW day, $191 per MW day and $ 178 per MW day.
- On August 21, 2007, the Commission issued Order No. 7263 opening PSC Docket No. 60 to consider promulgating rules that will govern Delmarva's development of the IRP for SOS customers. Pursuant to Order No 7263, Staff drafted proposed IRP rules and on November 14, 2007 submitted a proposed "Integrated Resource Planning Regulation." In Order No. 7318, issued December 4, 2007, the Commission accepted Staff's draft rules and initiated a formal rule making as dictated by the Administrative Procedures Act.[13]
- The RFP process, which began in 2006, generated large scale interest in Delaware's energy future among the public, the Commission, the State Agencies,

[12] On December 22, 2006, the FERC approved, with conditions, a settlement regarding PJM's reliability pricing model, finding that it ensures just and reasonable rates. ER05-1410-000,001 and EL05-148-000,001.

[13] See Order No. 7318, issued December 4, 2007

legislators and the media. Media coverage of events related to the RFP process was extensive . It is clear that there is a desire by all parties for renewable resources to play a significant role in Delaware's energy future, and therefore renewable resources should continue to be a part of the resource portfolio going forward. The RFP process also highlighted the need for stakeholder input, feedback, and participation in the planning process.

- On February 14, 2008 the Company issued a renewable or "Green" RFP targeting onshore and offshore wind energy developers to procure contracts of various size and term for renewable energy supply to meet the RPS needs of RSCI customers. To date, Delmarva has received formal notices of intent to bid by approximately a dozen developers, offering approximately 20 wind farm facilities representing over 2,000 MW of nameplate capacity.
- On February 28, 2008, PJM announced to its members that it will perform an evaluation of the performance of the Reliability Pricing Model ("RPM") in addressing industry infrastructure issues. This evaluation is expected to be completed by June 30, 2008.

These events are significant milestones for Delmarva's and Delaware's energy future. Delmarva views the submission of this updated IRP as an opportunity to reflect the progress that these events represent and to provide further discussion of the options for Delaware's energy future. Delmarva also views this updated IRP as a way to present the Company's plans to constructively move forward. The results, conclusions and recommendations of this IRP are based upon updating the IRP filed December 1, 2006 with new data and include the extensive guidance provided by the events described above.

III. Conclusions and Recommendations

1. Summary of Conclusions:

a. Portfolio Management

i. Depending on the timing of Commission authorization, the size of the RSCI SOS customer portfolio is expected to be about 226 MW of Peak Load beginning June 1, 2009 growing to about 591 MW on June 1, 2011.

ii. There is no single resource or option that is the "silver bullet" for procurement purposes; all available resources have plusses and minuses and any portfolio implemented for SOS procurement needs to achieve a balance among resources.

iii. An actively managed portfolio will need to obtain energy, capacity, ancillary services, transmission services and meet the Delaware Renewable Portfolio Standards requirements for SOS customers.

iv. Unbundling energy from full requirements SOS supply and matching purchases to changing loads will require portfolio resources to include both spot market purchases and spot market sales. These spot market transactions will balance the hourly load with the other resources in the portfolio. Likewise, capacity and ancillary services will be transacted in short term markets to effect balancing of daily requirements.

v. An actively managed portfolio will lead to situations where, in a given period of time, SOS supply costs may not equal SOS supply revenues. Therefore some type of true-up mechanism is needed.

vi. Long-term contracts in support of SOS obligations should include various sizes and combinations of features. Before entering into a long-term agreement, the portfolio manager needs to consider how the long-term obligation overlays on SOS customer electrical requirements and the impact of any specific contract commitment on the portfolio management objectives and risk management.

vii. Residential and Small Commercial customers demonstrate less propensity to shop; therefore, longer-term resources may be more appropriate for this customer class than for the larger commercial class customers. The portfolio must balance for these differences.

viii. Since the IRP was filed Dec 1, 2006, the effective RPS standards have doubled. Delmarva's procurement plan will meet and potentially exceed the new RPS standards. These green resources will be part of the SOS Resource portfolio.

ix. To obtain Renewable Energy Credits ("RECs") as needed to satisfy the RPS requirements and the associated green energy, Delmarva issued an RFP for green wind resources on February 14, 2008. As long as cost-effective bids on favorable terms are achieved through this process, Delmarva expects green energy to be available for SOS customers from this solicitation as early as June 1, 2009.

x. There are many important issues to decide regarding the implementation and operation of an actively managed resource portfolio prior to its implementation. These issues include portfolio structure, risk management, and appropriate cost recovery mechanisms. These issues are challenging but not insurmountable.

xi. Active management of the SOS procurement portfolio should be implemented over time in an orderly and staged manner consistent with the expiration of existing SOS contractual obligations and EURSCA requirements.

b. Reliability and Generation

i. Delmarva's transmission system is expected to meet established national, regional and local reliability criteria over the planning term of this IRP.

ii. Completion of the Transmission facilities identified in Delmarva's base reliability planning case, including the MAPP project, will provide adequate reliability for Delmarva's customers over the planning period at reasonable cost.

iii. Over the planning period, the total of generation resources within the Delmarva Zone and transmission import capability into the Zone will exceed the expected load within the Zone.

iv. At the request of the PSC, Delmarva has conducted two sensitivity analyses:

- The effect of retirement of various generators located on Delmarva South[14].
- The effect of a delay in the completion of the Bay Crossing portion of the MAPP project

[14] In accordance with PJM's tariff, generators that are planning to retire in PJM are required to notify PJM. PJM would then conduct its own independent analyses to identify necessary transmission enhancements in coordination with the specific transmission owners.

Delmarva's sensitivity analyses in response to the DE PSC's request were completed in a manner consistent with PJM's methodology for performing retirement studies. The results show that under both scenarios, reliability will be met by modifying the base reliability plan to include additional transmission enhancements.

v. If the Commission were faced with a situation where: 1) reliability in the State was threatened due to a lack of generation and 2) generation was the most cost-effective remedy for maintaining reliability and 3) the market was not forthcoming with new generation projects that would resolve the reliability issue in the State, then from the customers' point of view, it may be preferable for the Commission to require Delmarva to install and operate a generating facility rather than entering into a long-term purchase power agreement with a private developer for a similar facility.

vi. The construction and operation of regulated generation assets in Delaware may provide additional reliability and economic benefits to customers. Delmarva is willing to construct and operate a regulated generation facility for purposes of further securing reliability and other customer benefits under either traditional regulation or its functional equivalent with the appropriate regulatory treatment.

c. Demand Response Programs

i. Energy conservation and Demand Response represent cost-effective opportunities to reduce energy consumption and peak load.

ii. Since the filing of the IRP on December 1, 2006, the State of Delaware has established the Sustainable Energy Utility. The SEU will have responsibility for identifying, designing, implementing and monitoring cost-effective energy efficiency and conservation programs in the state. Delmarva will remain responsible for Demand Response programs including load control programs.

iii. The SEU has prepared a projection of Energy Efficiency and Conservation savings. The SEU projects annual demand and energy savings of about 100 MW and 162,634 MWh by 2016.

iv. Delmarva has already filed applications for implementing Demand Response programs as part of the "Blueprint" filing. Delmarva currently estimates that these demand response programs will provide annual demand and energy savings of about 229 MW and 36,153 MWh by 2016.

v. Decoupling distribution revenue from energy sales to remove any disincentive/systemic penalty for the Company to promote energy efficiency and demand response programs is an important enabling mechanism for these programs to be fully successful.

vi. Implementation of Advanced Metering Infrastructure ("AMI") will greatly enable the range of potential demand response and energy efficiency programs.

vii. Once installed, AMI can be used to design new rate structures such as "Critical Peak Rebate" or "Critical Peak Pricing" structures. These potential rate structures will require ongoing discussions to determine the best approach for Delaware.

2. Summary of Recommended Actions:

Delmarva's IRP recommended actions are designed to respond to the challenges of Delaware's energy future. Consequently, these recommendations call for the implementation of numerous changes to the status quo in Delaware. Delmarva respectfully recommends that the Commission acknowledge the updated IRP on a timely basis so that Delmarva can begin the following:

a. Portfolio Management

Delmarva is prepared to accept the responsibility and challenges of actively managing a resource portfolio for procuring SOS customer energy requirements. The portfolio could be composed of a variety of resources of different types, terms and attributes including longer term resources, green resources and regulated assets. Prior to submitting a specific portfolio for Commission approval, Delmarva strongly recommends that the rules and guidelines governing the management and operation of the portfolio be formalized. This will allow the "rules of the road" to be established prior to the portfolio being implemented.

As of the current date, the first window of opportunity for Delmarva to possibly begin managing a resource portfolio for SOS energy procurement will be on June 1, 2009 when approximately one third of the already in-place RSCI full requirements service SOS contracts expire. If this date cannot be met, the next "window" would not open until June 1, 2010.

Given the importance to Delaware's energy future of establishing a managed resource portfolio, Delmarva respectfully suggests that the Commission take appropriate and timely actions to allow Delmarva to begin actively managing a resource portfolio possibly as early as June 1, 2009.

Consistent with this objective, Delmarva recommends the following:

i. Upon acknowledgement of this updated IRP, the Commission authorize the creation of a collaborative working group to be known as the "Portfolio Working Group" composed of representatives of Delmarva, Staff, and the Delaware Division of the Public Advocate ("DPA").

ii. The Portfolio Working Group should be directed to establish proposed rules and guidelines for operating and managing the portfolio including, but not limited to, the following topics:

    a. Obtaining resources through contracts of various terms for fixed quantities of energy and capacity;

    b. Establishing hedge positions with fuel contracts associated with specific generator types;

    c. Establishing limits for the amount of spot and short term purchases to be used to balance the differences between customer load and portfolio resources;

    d. Promulgating rules and regulations governing the conduct and operation of the active management of the supply resource portfolio;

e. Proposing contracts for unit specific generation, and/or new utility owned generation to be included in rate base to meet reliability or electricity price hedging objectives;

f. Developing and recommending monitoring and reporting requirements; and

g. Developing and recommending risk mitigation practices.

iii. The Portfolio Working Group should make specific recommendations regarding cost recovery, the implementation of non-bypassable distribution charges, possible restrictions of customer choice, the operation and frequency of true-up mechanisms related to portfolio operation, and a procedural process and schedule to implement the results..

iv. After authorization of the Portfolio Working Group, Delmarva estimates that it will take approximately four months to prepare a set of findings and recommendations for Commission review. As the portfolio manager, Delmarva will take the responsibility for scheduling the meetings of the working group to assure that the work is completed on schedule. Delmarva will have the responsibility to file under separate application the recommendations of the Portfolio Working Group for Commission review and approval. If a decision can be reached by October 15, 2008, Delmarva can curtail the Full Requirements SOS contract procurement process for June 1, 2009 delivery.

v. As approved by the Commission, Delmarva will transition the existing SOS customer energy procurement process to a more actively managed resource portfolio. The portfolio will be managed by the objectives of achieving price stability, reasonable cost, and meeting the Renewable Portfolio Standards.

vi. When available, Delmarva will provide summary information on the bids received in response to the green energy RFP issued on February 14, 2008 by Delmarva. This information will be in summary format (to protect the confidentiality of individual bidders) and provided as an addendum to the March 5, 2008 IRP filing.

vii. Any proposed Power Purchase Agreement(s) between Delmarva and a green energy provider that emerges as a result of the February 14, 2008 Green RFP process will be submitted to the Commission for approval under separate application.

viii. Delmarva will examine other renewable alternatives in addition to wind resources. Delmarva anticipates providing the results of this examination in the December 1, 2008 IRP filing.

ix. Delmarva will develop a program (or programs) to allow customers the opportunity to purchase additional green energy and or REC's over the RPS. Delmarva anticipates having this program (or programs) included as part of the December 1, 2008 IRP filing.

b. Reliability and Generation

Delmarva’s power transmission system meets all national, regional and local reliability standards. Delmarva’s base plan is to meet the electrical reliability needs of its Delaware customers through specific transmission investments. PJM has approved the 500kV portion of the MAPP transmission project that is expected to significantly increase import capability into Delmarva and Delmarva South. If additional generation units within the Zone are retired, Delmarva has identified the additional transmission investments that would need to be approved and implemented to maintain electrical reliability.

The construction and operation of regulated generation assets in Delaware may provide additional reliability and economic benefits to customers. Delmarva Power is willing to construct and operate a regulated generation facility in Delaware for purposes of further securing reliability and other customer benefits under either traditional regulation or its functional equivalent with the appropriate regulatory treatment. Under traditional regulation of generation, the cost of the generation asset was allowed in the Company's rate base, the generation asset was subject to regulatory accounting, fuel cost recovery mechanisms were in place and there was no customer choice. If the Commission is interested in Delmarva pursuing options related to regulated generation, Delmarva respectfully suggests the following:

i. The Commission direct the Portfolio Working Group described above to propose a regulatory framework for including regulated generation assets in rate base, the mechanism and frequency for fuel and other cost recovery associated with operation of a regulated generation asset and the implementation of non-bypassable charges or restrictions of customer choice.

ii. Concurrently with the initiation of the Portfolio Working Group and if authorized by the Commission, Delmarva conduct a preliminary generation feasibility study to review regulated generation alternatives for Delaware.

iii. Assuming that the Commission directs the Portfolio Working Group to review potential regulatory frameworks for regulated generation, the Portfolio Working Group recommendations regarding regulated generation will be included with the application filed by Delmarva regarding the portfolio management rules and regulations.

c. Demand Response Programs

Demand Response programs represent a good opportunity for Delmarva's customers to help take control of their own energy future. Consistent with this,Delmarva recommends that the Commission take the following actions:

i. Approve Delmarva Power's plan to establish an Internet-based Portal to the PJM Demand Response Market. Larger commercial, government, institutional, agricultural and industrial customers - those capable of reducing load by 100kW during a summer weekday afternoon – are sophisticated energy users who can take advantage of PJM's market-based conservation offerings.

ii. Approve Delmarva Power's proposed establishment of new residential and small commercial customer direct load control programs. These programs have worked in the past – new technologies will give these programs greater opportunity to lower peak demand.

iii. Establish cost recovery methods for new demand response initiatives and deployment of advanced metering. This step is critical to advancing these programs.

iv. Approve a decoupling mechanism for Delmarva. This mechanism decouples revenue from sales and thus removes disincentives and systemic, yet unintended, penalties to implementing demand side management programs.

v. Accept the Advanced Metering Infrastructure recommendations from the Blueprint filing – including the creation of an AMI Working Group to review and report on AMI implementation issues. AMI is the principal technology driver for both demand response and critical peak pricing programs – but there are many program design issues, including the communications infrastructure, which must be settled before program implementation.

vi. Also charter the AMI Working Group to examine alternative dynamic pricing options, such as critical peak pricing. This program would allow Delaware's electric energy consumers to actively manage their own energy use. In an "interactive" and "internet" age, well informed consumers will make intelligent decisions about their energy use patterns.

IV. General Updates to the December 1, 2006 IRP

1. Updated Load Forecast

The December 1, 2006 IRP compliance filing submitted by Delmarva was based upon the PJM Load Forecast for the Delmarva Zone (the "Zone"). This forecast, released by PJM in January 2006, indicated an annual peak demand growth rate of 2% per year through 2016. The Delmarva Zone includes all of Delaware as well as areas of Maryland and Virginia located on the Delmarva Peninsula. PJM has recently released the 2008 Load Forecast for the Delmarva Zone. The 2008 PJM forecast indicates a new projected annual 10 year growth rate of 1.9%. Table 1 below shows a comparison of the 2008 PJM Delmarva Zone forecast with the 2006 PJM Delmarva Zone forecast.

Table 1

PJM DPL ZONE MW Forecast

Forecast Year	Updated	Original IRP	delta MW
2008	4,192	4,150	42
2009	4,278	4,244	34
2010	4,360	4,313	47
2011	4,442	4,403	39
2012	4,522	4,491	31
2013	4,617	4,587	30
2014	4,699	4,700	-1
2015	4,781	4,792	-11
2016	4,874	4,870	4

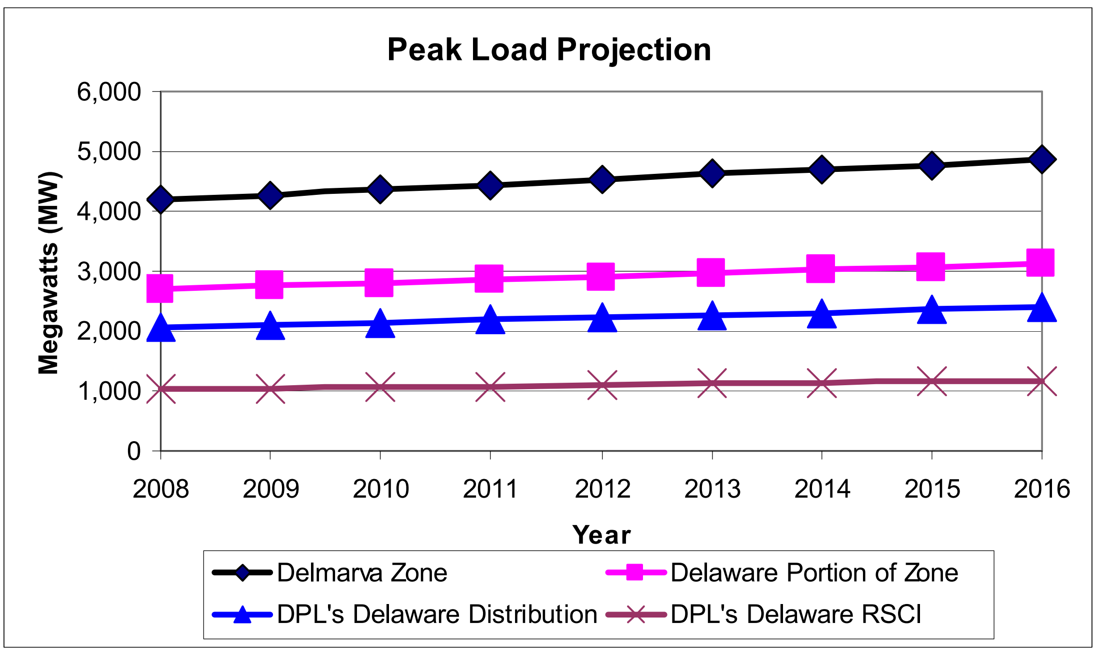
Table 2 and Chart 2a below show the breakdown of the updated Delmarva Zone load forecast into total Delaware, Delmarva Delaware, and the Residential and Small Commercial and Industrial ("RSCI") customer group.

Table 2

DPL RSCI MW Forecast

Forecast Year	DelMarVa Zone	Delaware State	DPL/DE Distribution	DPL/DE RCSI
2008	4,192	2,696	2,066	1,018
2009	4,278	2,751	2,109	1,038
2010	4,360	2,804	2,149	1,058
2011	4,442	2,857	2,189	1,078
2012	4,522	2,908	2,229	1,098
2013	4,617	2,969	2,276	1,121
2014	4,699	3,022	2,316	1,141
2015	4,781	3,075	2,357	1,161
2016	4,874	3,134	2,402	1,183

Chart 2A



2. Updated Renewable Portfolio Standard ("RPS") and Green RFP

In July of 2007, the Delaware General Assembly passed legislation essentially doubling the RPS standards for Delmarva. Under this legislation and subsequent rules and guidelines issued by Staff, Delmarva is required to obtain Renewable Energy Credits in specified increasing amounts from 2% in 2007 up to 19% in 2019.

Each individual REC is a certificate that represents one MWh of energy that was created by a renewable resource. Each REC is only available to cover the Delmarva RPS obligation to the extent that there has been an operating green resource that produced energy and that green resource has registered that REC in the PJM Generation Attribute Tracking System ("GATS"). In addition to increasing the annual RPS percentage requirements, the new standards also included a provision that a minimum percentage of RECs or energy be provided from solar resources. These are often referred to as Solar RECs ("SRECs").

Table 4 below shows the original annual percentage RPS requirements as used in the December 1, 2006 IRP filing and the more recently enacted standards.

Table 4
Renewable Energy % Requirements

	December 1, 2006 IRP	March 5, 2008 Update	March 5, 2008 Update
	Senate Bill 74	Senate Bill 19	Senate Bill 19
Compliance Year (Beginning June 1st)	Cumulative Minimum Percentage	Minimum Cumulative Percentage from Eligible Energy Resources*	Minimum Cumulative Percentage from Solar Photovoltaics
2007	1.0%	2.0%	--
2008	1.5%	3.0%	0.011%
2009	2.0%	4.0%	0.014%
2010	2.75%	5.5%	0.018%
2011	3.5%	7.0%	0.048%
2012	4.25%	8.5%	0.099%
2013	5.0%	10.0%	0.201%
2014	5.75%	11.5%	0.354%
2015	6.5%	13.0%	0.559%
2016	7.25%	14.5%	0.803%

*Minimum Percentage from Eligible Energy Resources Includes the Minimum Percentage from Solar Photovolatics

**A Retail Energy Supplier shall receive 300% credit toward meeting the RPS for energy derived from the following sources installed on or before December 31, 2014:

- Solar electric; or
- Renewable fuel that is used in a fuel cell

***A Retail Electricity Supplier shall receive 150% credit toward meeting the RPS for wind energy installations sites in Delaware on or before December 31, 2012.

Based upon the percentage requirements shown in Table 4 above, Table 5 below shows the projected REC's that must be acquired to supply Delmarva's RSCI customers to comply with the Delaware RPS legislation and guidelines. There are no numbers shown for 2008 in the table because the REC requirements for 2008 are already fully subscribed with existing FRS contracts.

Table 5

DE RPS REC Requirement

Future RSCI REC Requirement			
Compliance Year (begins June 1st)	Total DE RSCI GWHs	Non-Solar RECs Required	Solar RECs Required
2008	-	-	-
2009	3,266,	43,396	51
2010	3,329	121,654	133
2011	3,391,	235,766	543
2012	3,452	290,038	1,139
2013	3,525	345,410,	2,362
2014	3,588	399,869	4,233
2015	3,650	454,116	20,404
2016	3,721	509,688	29,881

The amounts listed in the Table above do not include the RECS that are part of existing Full Requirements Service ("FRS") contracts. A complete listing of the eligible renewable resources that qualify to receive REC's under the State of Delaware RPS program is provided in Appendix A.

As described above, the annual REC requirement increases substantially over the next few years indicating that it will become a more significant part of the overall electricity portfolio. Delmarva issued an RFP for green wind resources on February 14, 2008. All RECs and green energy that are eventually secured through contracts resulting from this RFP would serve as resources within the managed portfolio.

Delmarva believes that issuing the RFP for Green wind resources at this time is the right thing to do for any number of reasons. It is clear from the many recent public hearings and forums and our own customer research survey[15] that Delmarva's customers are supportive of cleaner renewable energy alternatives and issuing the RFP now could potentially allow for delivery of green energy to these customers as early as June 1, 2009. Delmarva also believes that the RFP will provide for competition among many suppliers and that such competition will likely lead to response bids that vary by size, term, technology and price. This variation will allow Delmarva, as the portfolio manager, to consider those responses to the RFP that best fit the needs of the portfolio[16]. In fact, it may even be possible to construct a "mini-portfolio" of wind resources from the responses to the RFP depending on the specific responses. It is believed that the wind only RFP will result in the acquisition of green energy and RECs at the lowest reasonable costs, in the most cost-effective manner.

As of this filing, Delmarva has not had the opportunity to review the responses to the RFP. Because of the public interest in the green RFP, it is Delmarva's intent to make this information publicly available in summary form (so as to protect the confidentiality of the individual bidders). Delmarva can provide this information as an addendum to this IRP as it becomes (non-confidentially) available.

Although the recent green RFP is focused on wind resources and wind resources are likely to form the most substantial portion of the renewable portfolio, Delmarva believes that other Delaware RPS eligible renewable technologies should also be explored. Consequently, Delmarva's intends to investigate other renewable

[15] The results of Delmarva's survey can be found on the web at www.delmarva.com
[16] This includes the risk management aspects of active portfolio management to be discussed by the Portfolio Working Group.

technologies in addition to wind as time permits. Also, as filed in Delmarva's Blueprint for the Future, Delmarva believes that customers should have the opportunity to exceed state required RPS targets. To this end, Delmarva will continue to pursue optional programs that will allow customers to voluntarily elect to purchase additional amounts of RECs and green energy. Delmarva anticipates providing additional information on renewables other than wind and optional programs for customers to purchase additional RECs and green energy in the December 1, 2008 IRP filing.

Finally, it should be noted that Delmarva will not enter into a Power Purchase Agreement ("PPA") with any of the bidders in response to the RFP without prior Commission approval and authorization. Delmarva would expect to request such approval and authorization after carefully reviewing the response bids and filing a separate application for such approval with the Commission. This application would be subject to all applicable rules and regulatory procedures.

3. Updated Energy Efficiency and Demand Response

DSM and Demand Response programs were key components of the December 1, 2006 IRP compliance filing. In the spring of 2007, the General Assembly created the Sustainable Energy Utility. The SEU's principle mission is to design, implement, and monitor energy efficiency and conservation programs in a cost-effective and timely manner to the maximum benefit of Delaware. Consequently, moving forward, Delmarva will not be responsible for implementing energy efficiency and conservation programs, as this will be the SEU's responsibility. Delmarva will, however, continue to be responsible for designing, implementing and monitoring cost-effective Demand Response programs. DR programs include dynamic pricing and direct load control. Delmarva has proposed several DR programs through the Blueprint for the Future application filed February 6, 2007. The Blueprint will be discussed in more detail later in this document.

The SEU has prepared its own forecast of energy savings resulting from the cost-effective energy reduction programs it intends to implement. Tables 6A and 6B below provide a comparison for 2008-2016 of the initial DR and energy efficiency savings provided in the December 1, 2006 IRP compliance filing with the updated SEU and Delmarva estimates.

Table 6A

Demand Response Programs

	kW		MWH	
	Original	Updated	Original	Updated
2008	12,280	28,005	333	333
2009	25,329	46,054	687	737
2010	40,365	63,590	1,095	1,170
2011	45,892	172,158	1,246	6,604
2012	52,176	201,107	1,417	14,349
2013	59,320	244,471	1,611	22,537
2014	67,442	275,045	1,832	30,407
2015	76,677	302,878	2,084	38,212
2016	79,295	307,997	2,155	38,308

Table 6B

Energy Efficiency Programs

	kW		MWH	
	Original	SEU	Original	SEU
2008	4,022	0	15,690	0
2009	8,035	25,237	31,995	41,085
2010	12,193	51,420	48,453	83,729
2011	15,931	61,144	60,567	99,542
2012	20,545	71,196	78,829	115,933
2013	26,219	78,002	102,720	127,012
2014	33,175	81,330	133,917	132,460

2015	41,677	86,680	175,962	141,145
2016	48,385	99,879	203,112	162,634

4. Updates to PJM, RPM and RTEP Processes

PJM's Regional Transmission Expansion Planning process identifies transmission system upgrades and enhancements to preserve the reliability of the electricity grid. The RTEP recommends transmission upgrades to address near-term needs within five years and assesses long-term needs that require a planning horizon of 10-15 years. In addition, Delmarva worked cooperatively with all distribution system owners on the peninsula in 2007 to establish the "Peninsula Planning Association". This group works proactively within the PJM process but with specific focus to the needs of the peninsula.

In 2007, the PJM's Board of Managers authorized significant electric transmission upgrades and additions, including three major transmission backbone projects. On October 17, 2007, the Mid-Atlantic Power Pathway ("MAPP") project, one of three backbone transmission projects was approved by the PJM Board. (Of the other two, one was sponsored by AEP and one by PP&L/PSE&G). Among other benefits, the MAPP project "also improves the ability to deliver electricity to customers on the Delmarva Peninsula. That area currently has both limited local generation and limited transmission, which comes only from the north. The new line will provide a robust transmission path into the southern end of the peninsula."[17]

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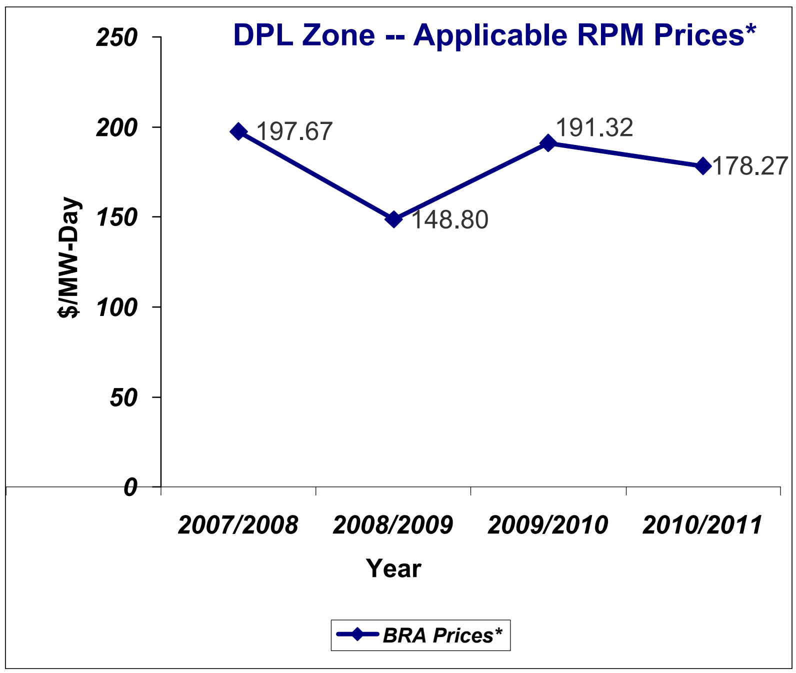
[17] "PJM Board authorizes $2.1 billion in transmission additions, upgrades" PJM news release, Oct. 17,2007

On December 22, 2006, the Federal Energy Regulatory Commission approved, with conditions, a settlement regarding PJM's Reliability Pricing Model (":RPM") which is a 3-year forward capacity market. In order to phase-in this 3-year forward market, three Base Residual Auctions were conducted in 2007. In April 2007, PJM implemented the first annual capacity auction under RPM for the 2007/2008 delivery year Two Base Residual Auctions, which were part of the phase-in were subsequently held later in 2007 for the 2008/2009 and 2009/2010 delivery years.



In January 2008, PJM held the Base Residual Auction for 2010/2011 delivery year for 23 Locational Deliverability areas ('LDAs') including the DPL Zone. PJM is divided into appropriate areas that include parts or combinations of the PJM Electric Distribution Company ('EDC") territories. These areas are referred to as Locational DeliverabilityAreas in RPM. On February 1, 2008, PJM posted the results of this auction. Over the period covering the first four RPM auctions, 4,364.7 MW of new capacity MW were added which were partially offset by 1,902.0 MW of capacity derations or retirements over the same period. Additionally, 1,373.4 MW of new Demand Resources were cleared over these first four auctions. The total net increase in installed capacity over the period of the first four RPM auctions were 3,836.1 MW.

The DPL South LDA was a constrained LDA in the 2010/2011 Base Residual Auction as a result of limited internal generation and import limitations into the LDA. For 2010/2011 delivery year, the Capacity Emergency Transfer Obligation ("CETO") and Capacity Emergency Transfer Limit ("CETL") were calculated to be 1430MW and 1437MW respectively. The transmission import capability required ("CETO") into each LDA is determined using the generation reliability model to meet an area Loss of Load Expectation ("LOLE") criterion of one day in 25 years. The transmission import capability to each LDA ("CETL",) is calculated using the transmission analysis models. If CETL is less than CETO, additional transmission is planned. For the 2010/2011 planning period the constrained facility in the DPL South LDA was identified to be a 69kV circuit. This circuit is planned to be upgraded by the summer of 2011/2012. The 2011/2012 CETO and CETL for DPL-South are calculated to be 1710MW and 1857MW, respectively. The addition of MAPP is expected to increase the import capability ("CETL") into DPL by more than 1000MW providing a comfortable reserve.

On February 28, 2008, PJM announced to its members that it will perform an evaluation of the performance of the Reliability Pricing Model in addressing industry infrastructure issues. As markets evolve, PJM continues to evaluate its rules and programs to ensure that they are working as intended. According to PJM, the evaluation of RPM will provide: 1) an overall assessment of whether the RPM is working as expected to address the infrastructure investment issues that were driving capacity market reforms, and, 2) recommendations for modifications to RPM, if necessary, to improve its performance in maintaining resource adequacy consistent with relevant reliability requirements. A report summarizing the results of this evaluation is expected to be available June 30, 2008. A copy of PJM's letter to its membership describing this RPM evaluation is provided as Appendix E. Delmarva Power, along with the recently formed Delmarva Peninsula Planning Association, will work with PJM to ensure issues affecting the region are considered. Delmarva will integrate PJM findings into future IRP plans as they become available.

V. Portfolio Management

Implementation of a resource portfolio provides an opportunity for Delmarva to more actively manage the electrical requirements of SOS customers. In the December 1, 2006 IRP compliance filing, Delmarva recommended continuing with the SOS procurement process currently in place. Updating the IRP to include the implementation of an actively managed resource portfolio for SOS energy procurement represents a significant departure from the December 1, 2006 IRP.

Commission Order No. 7199, issued in May 2007, adopted the May 2, 2007 Staff report recommendation that the Company adopt a portfolio planning approach for energy supply. Thus this IRP must deal with the most appropriate and reasonable course of action to take in implementing a managed resource portfolio for Delmarva's SOS customers.

The remainder of this section is devoted to describing where Delmarva currently stands with the current SOS procurement process and how to best transition the procurement process to an actively managed resource portfolio including green resources. This section is organized as follows:

1. **Expiration of existing full requirements service contracts**
2. **Size and nature of portfolio to be managed**
3. **Product nature of the PJM Market**
    a. Energy
    b. Capacity Market
    c. Renewable Energy Credits ("RECs")
    d. Ancillary Services

e. Transmission Service

4. Potential Resource Options

a. Market Resources

b. Long Term Contracts and Resources

i. Expectations of Long-term Resources within a Portfolio

ii. Long-term Resources as a Hedge against Future Price Increases

iii. Resource Size and Fixed Volume Requirements

iv. Firm vs. Unit Contingent Contracts

v. Intermittent Renewable Resources

vi. Longer-term Fuel Contracts as Hedges

vii. Regulated Generation Assets

5**. Portfolio Risk Management for Standard Offer Service ("SOS") Procurement**

a. Elements of Portfolio Procurement and risk Management

b. Analysis of Demonstrative Portfolio

c. Results for Illustrative Portfolios

d. The Role of Physical Assets in SOS Supply

e. Process for SOS Procurement Specification

6. Portfolio Management Implementation issues:

a. Non bypassable distribution charges and Restriction of Customer Choice

b. Power Supply Cost and Revenue Imbalance

c. Portfolio Management Objectives

d. Portfolio Risk Management

e. Portfolio Implementation Schedule

7. Resource Portfolio Suggested Path Forward

1. Expiration of Existing Full Requirements Service Contracts:

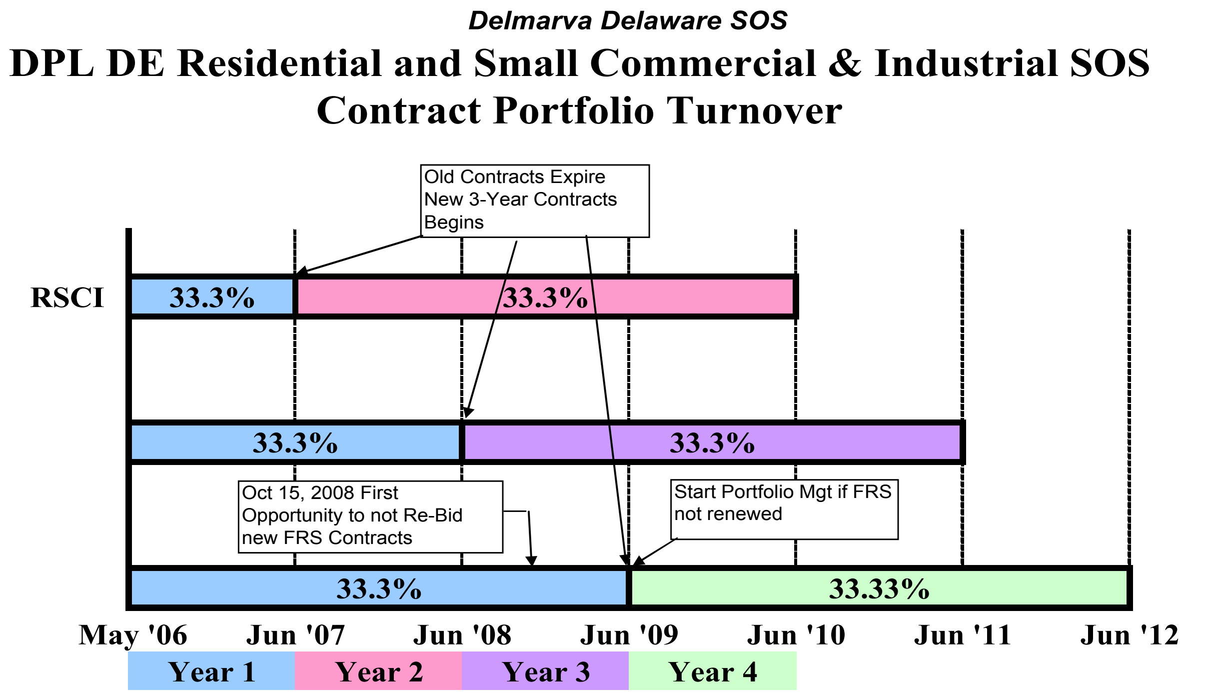
The current SOS procurement process, as implemented in May 2006, relies upon full requirements service contracts ("FRS") to obtain the electrical requirements of Delmarva's SOS customers. Depending on the customer class, the term of these contracts is between one and three years. For the Residential and Small Commercial customers, all FRS contracts obtained after May 2006 have had a three year term. The term for these contracts begins on June 1 and expires three years later on May 31. The contracts are "layered" so that each years FRS contracts represent about one-third of the total SOS RSCI load and electrical requirements. Consequently, approximately one third of the outstanding contracts expire on May 31 of each year.

In order to obtain new FRS contracts that will become effective on June 1 of each year, a competitive auction process begins in the Fall of the preceding year and is finalized in late February of the next year. As of this filing, the next round of new FRS contracts, which have recently been executed, is scheduled to begin delivery on June 1, 2008.

As currently practiced and authorized, the lead time from start to finish for the FRS contract implementation is approximately 8-9 months. Consequently, as Delmarva transitions to implementation of an actively managed resource portfolio, consideration needs to be given as to when to curtail further auctions for FRS contracts and when the existing FRS contracts expire.

The scheduling issue this presents is illustrated in Chart RP-1 below. Chart RP-1 shows the existing schedule for the procurement of FRS contracts for SOS RSCI customers and the expiration of outstanding FRS contracts.

Chart RP-1



Because the FRS contracts that begin June 1, 2008 are already completed, the first window of opportunity for Delmarva to begin actively managing a resource portfolio would be June 1, 2009. As will be discussed later in this document, if the appropriate decisions to implement portfolio management can be reached by October 15, 2008, then the June 1, 2009 FRS contract process can be curtailed and Delmarva can begin acquiring resources to start active portfolio management on June 1, 2009. However if the appropriate decisions to implement portfolio management cannot be reached by October 15, 2008, then the June 1, 2009 FRS contract process needs to proceed and the next window of opportunity for implementation of portfolio management will shift to June 1, 2010.

Given Delaware's RPS requirements and the interest of Delmarva customers in green energy and in anticipation of the implementation of an actively managed resource portfolio as early as June 1, 2009, Delmarva issued an RFP for green wind resources on February 14, 2008. This opens the door for green resources to become part of the SOS procurement portfolio and provide benefits to customers as early as June of 2009.

2. Size and Nature of the Portfolio to be Managed:

The size of the portfolio to be managed is critical in determining the most appropriate combination of resource options to include within the portfolio. Because the size of the portfolio depends upon the electrical needs of the SOS customers being served, it is also critical to understand the nature and characteristics of those needs. Table RP-2 and Chart RP-2a below provides Delmarva's projections of the potential size of the RSCI SOS resource portfolio in MW between 2008 and 2016. Table RP-3 provides the projected size of the RSCI portfolio in terms of GWh.

Table RP-2

DPL RSCI Projected Portfolio Peak MW size

Forecast Year	RSCI Peak MW	Less Total DSM	Less 30% FRS Auction	FRS* Phase-Out	Net RSCI Portfolio**
2008	1,018	990	693	100.0%	0
2009	1,038	967	677	66.6%	226
2010	1,058	943	660	33.3%	440
2011	1,078	845	591	0.0%	591
2012	1,098	825	578	0.0%	578
2013	1,121	798	559	0.0%	559
2014	1,141	784	549	0.0%	549

2015	1,161	771	540	0.0%	540
2016	1,183	775	543	0.0%	543

* The FRS contracts expire June 1 of each year

** portions of the RSCI portfolio must be met by RPS eligible renewable resources

Chart RP-2a

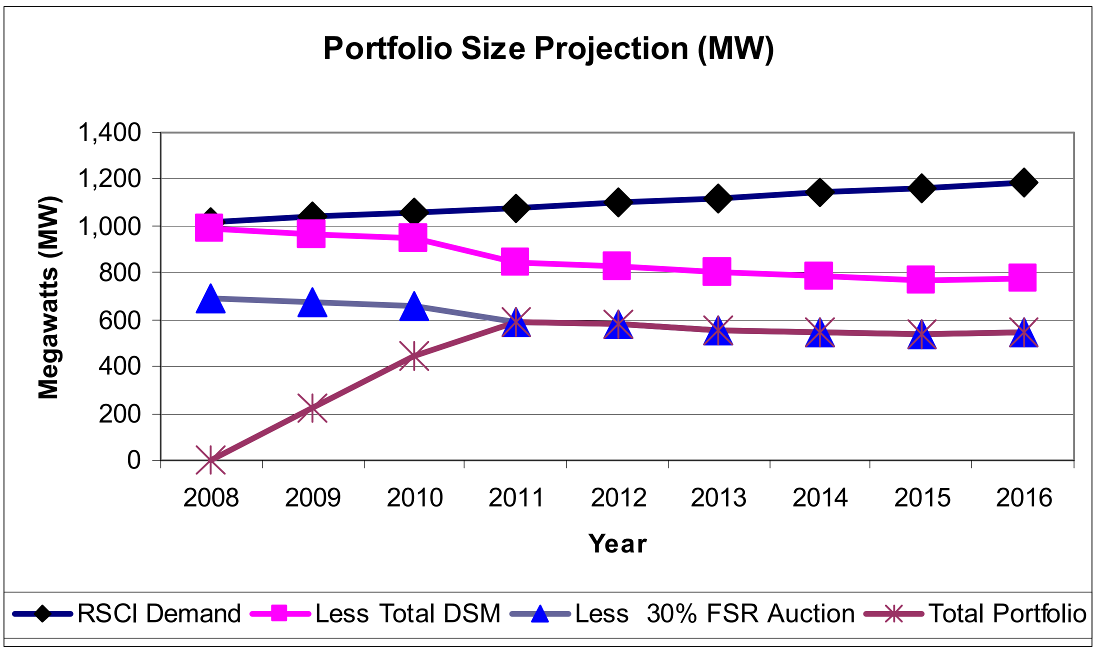


Table RP-3

DPL RSCI Projected Portfolio Peak GWH size

Forecast Year	RSCI Peak MW	Less Total DSM	Less 30% FRS Auction	FRS* Phase-Out	Net RSCI Portfolio**
2008	3,200	3,200	2,240	100.0%	0
2009	3,266	3,224	2,257	66.6%	754
2010	3,329	3,244	2,271	33.3%	1,515
2011	3,391	3,285	2,300	0.0%	2,300
2012	3,452	3,322	2,325	0.0%	2,325
2013	3,525	3,375	2,363	0.0%	2,363

2014	3,588	3,425	2,397	0.0%	2,397
2015	3,650	3,471	2,430	0.0%	2,430
2016	3,721	3,520	2,464	0.0%	2,464

* The FRS contracts expire June 1 of each year

** portions of the RSCI portfolio must be met by RPS eligible renewable resources

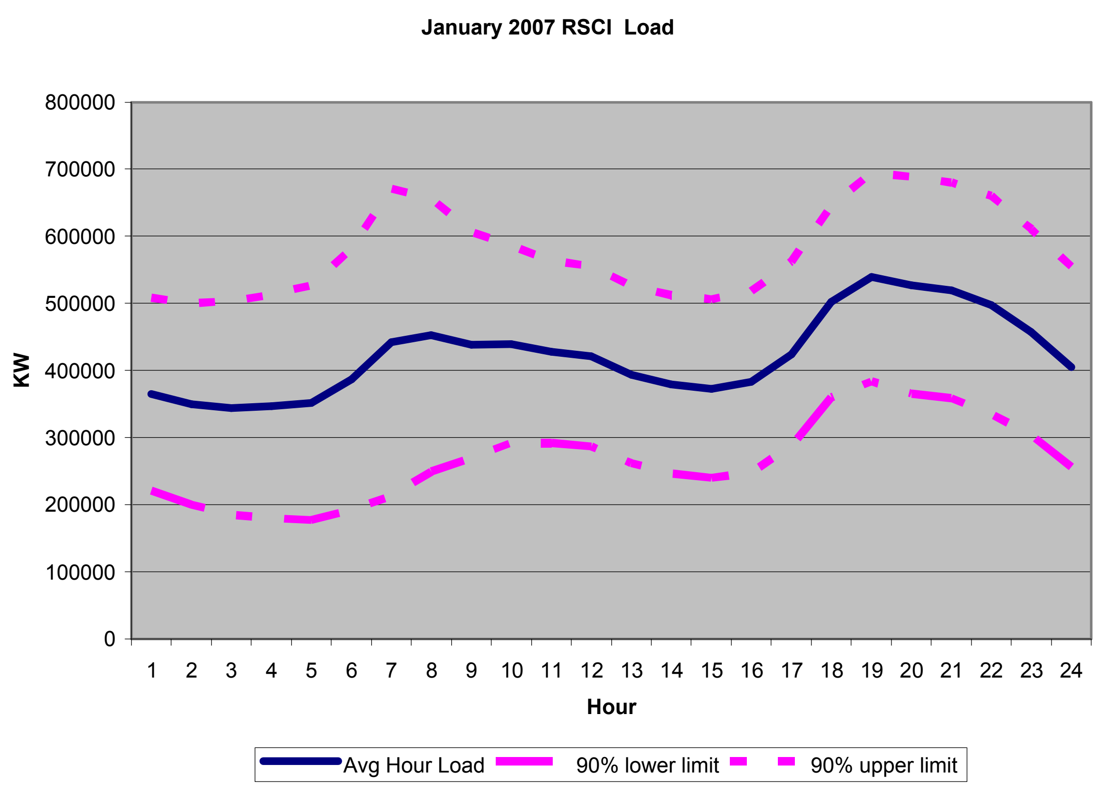
The second columns of the Tables provide the projection of the total RSCI requirements by year (assuming no migration). The fourth column of the Table represents the EURCSA requirement that at least 30% of the SOS requirements be sourced from the wholesale market. Delmarva considers the current FRS contracts to satisfy this requirement so this requirement does not affect the portfolio size until June, 1 2011. The fifth column of the table represents the projected percentage of outstanding FRS contracts obtained through the current SOS procurement process that will be phased out though June 1, 2011.

The RPS standards enacted by the General Assembly in 2007 require Delmarva to acquire REC's in increasing minimum percentage amounts between 2007 and 2019. In addition, the current RPS standards provide for a certain percentage of the green resources to be obtained exclusively from solar applications.(See Table 5 above). These requirements apply to all RSCI load including both the portions served by FRS and the resource portfolio.

While Tables RP-2 and RP-3 provide very useful information to a portfolio manager, they do not convey all of the needed information from a size perspective to manage a portfolio. From a portfolio manager's point of view, it is also important to recognize that the size of the RSCI load varies considerably over any 24 hour period, as well as from day to day and month to month. The portfolio manager's responsibility is to ensure that in each hour the resources within the portfolio can be balanced with these varying needs while minimizing risk to the extent possible. Appendix B provides graphical displays of four selected weeks of RSCI customer load data taken from recent historical periods. The point of including this information is to highlight the expected and yet uncertain nature of what must be procured through any resource portfolio *for each hour of the day*. Unlike most commodities which can be purchased now and physically stored for later use, electricity must be used "on the instant". This creates challenges and risks but also potential benefits for resource portfolio management.

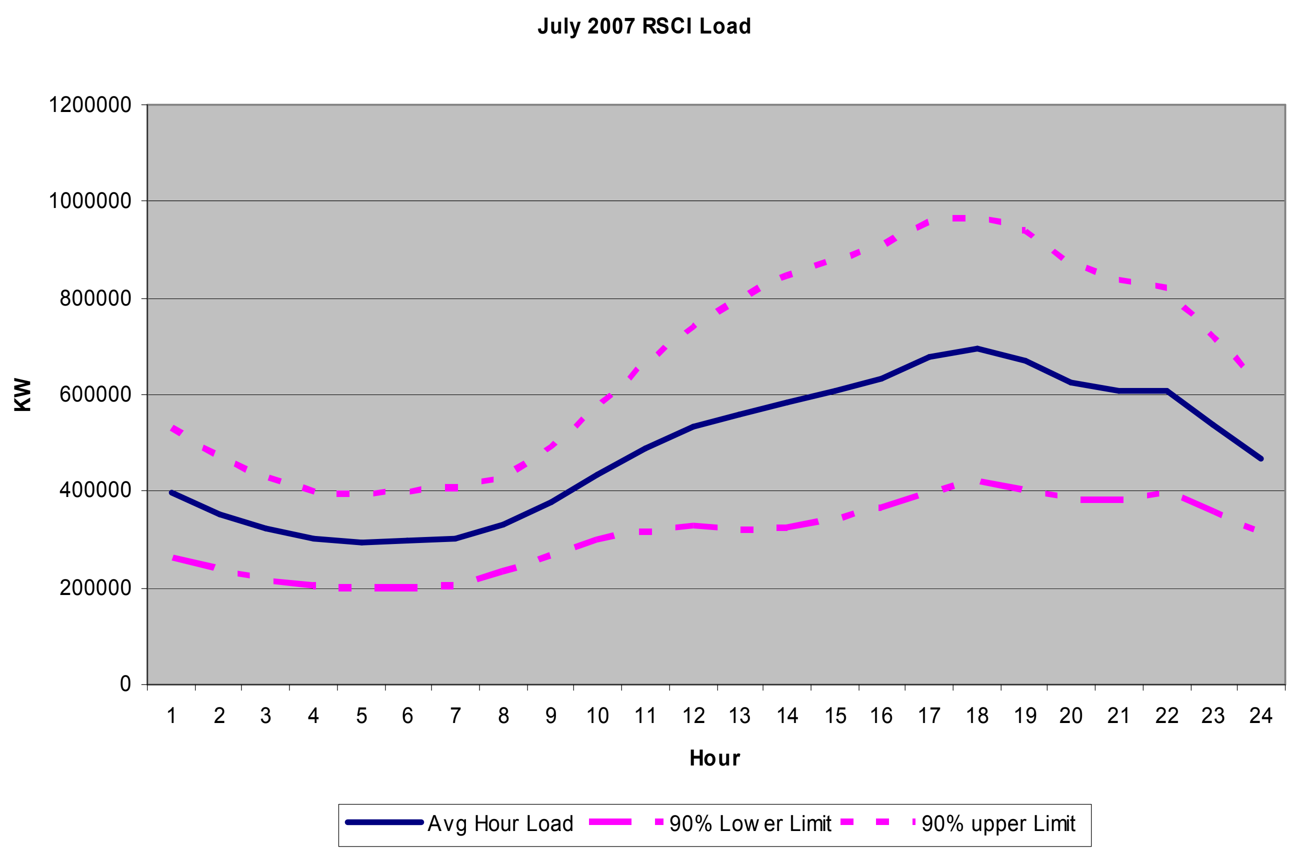
To gain an appreciation for the degree of variability in RSCI customer load, charts RP-4 and RP-5 below illustrate the average 24 hour load shape for RSCI customers for January 2007 and the average 24 hour load shape for July 2007. Also shown on these charts are estimates of the 90% confidence intervals of the RSCI load in each hour. The confidence intervals indicate the expected range of 90% of the possible outcomes. As can be seen by reviewing the graphs, the range of possible outcomes is fairly large and this presents challenges to managing a resource portfolio.

Chart RP-4



January 2007 RSCI Load
KW
800000
700000
600000
500000
400000
300000
200000
100000
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour
Avg Hour Load
90% lower limit
90% upper limit

Chart RP-5



3. Product Nature of the PJM Market:

In an unbundled electricity supply portfolio, DPL must acquire separately all the components of supply necessary to effect delivery into the DPL distribution system.

Among these components are energy, capacity, RECs, ancillary services and transmission. Delmarva's transition from FRS contracts (which provide all of these component services) to a managed resource portfolio where these components must be separately procured will need to recognize the nature and risks associated with each of the component markets as the portfolio is implemented and operated[18].

Each of the market components mentioned above is measured in a different way, and each component is acquired through a different market mechanism. Energy supply itself has several different sub-components including marginal losses, congestion and congestion hedging. The strategy for acquiring each component of electricity supply must be worked out separately, but in a coordinated manner. The following sections will briefly describe some features of the markets components and the methods for acquiring them.

a. Energy

Energy is measured in MWh for each hour of the day. Energy is provided by PJM to all loads at all times through the operation of the interconnected electric system. The acquisition of energy is therefore really a matter of entering into financial contracts to fix or hedge the cost of PJM's supply. There are two energy markets administered by PJM. The day-ahead market clears energy generation (supply) offered by PJM generators and load bids (demand) by the load serving entities. PJM matches the least cost generation offers to loads, and fixes a price for the loads as bid. The quantity of load and the associated price are

[18] DPL already has responsibility for procuring transmission service for its SOS customers and would continue to do so moving forward under either an FRS or managed portfolio approach.

established for each hour of the following day in this day-ahead market. During the actual day, in the spot, or real-time market, PJM dispatches available generation in a least cost manner to meet the actual load. For each hour this establishes a real-time price (locational marginal price, or LMP) for the energy actually being delivered. Loads that were submitted in the day-ahead market pay the day-ahead price. Mismatches each hour between the day-ahead load and the real-time load are priced at the real-time LMP. The mismatched loads also bear a pro-rata responsibility for real-time operating reserves charges that are associated with off-cost generation employed by PJM to meet reliability criteria on the system.

Secondary markets exist in which loads may contract for energy supplies with generators, or other parties who have access to energy on the PJM system. These bilateral markets serve to hedge the volatility of the PJM spot markets. Typically, buyers and sellers transact for fixed quantities of energy (eg: 50 MWh/hr) at fixed prices. These forward contracts can be disclosed to PJM to offset spot energy obligations, or may be used solely for financial settlement between the parties.

Energy prices are locational, as implied by the term "LMP." A MWh of energy delivered into the DPL zone may have a different price than a MWh delivered into the Pepco zone, for example. The difference in price is determined by PJM and represents the specific cost to dispatch generation to meet the load in each location while maintaining a reliable electric system network. The difference among the various PJM locational prices is referred to as congestion cost. The cost to supply load is specific to where it is needed, i.e. prices are locational, but a bilateral supply contract may not be delivered to the same location.   Therefore, the energy portfolio using bilateral contracts must also take account of congestion.

PJM operates a congestion hedging market to help load serving entities offset some of the uncertainty of hour-to-hour congestion costs. Load serving entities are given the opportunity to select an allocated share of historic electricity transmission paths.   These shares represent hedges of congestion. Loads can self schedule these hedges to financial transmission rights ("FTR") to hedge day ahead-time congestion or LSE's can allow PJM to auction these rights in the FTR market. Loads then receive the revenues from the auctions (Auction Revenue Rights or "ARR") if they were made available in the FTR auctions or can collect the revenues as a result of owning the FTRs. Either choice can be considered financial hedges to the costs of congestion.   Energy portfolios must include consideration of available congestion hedges.

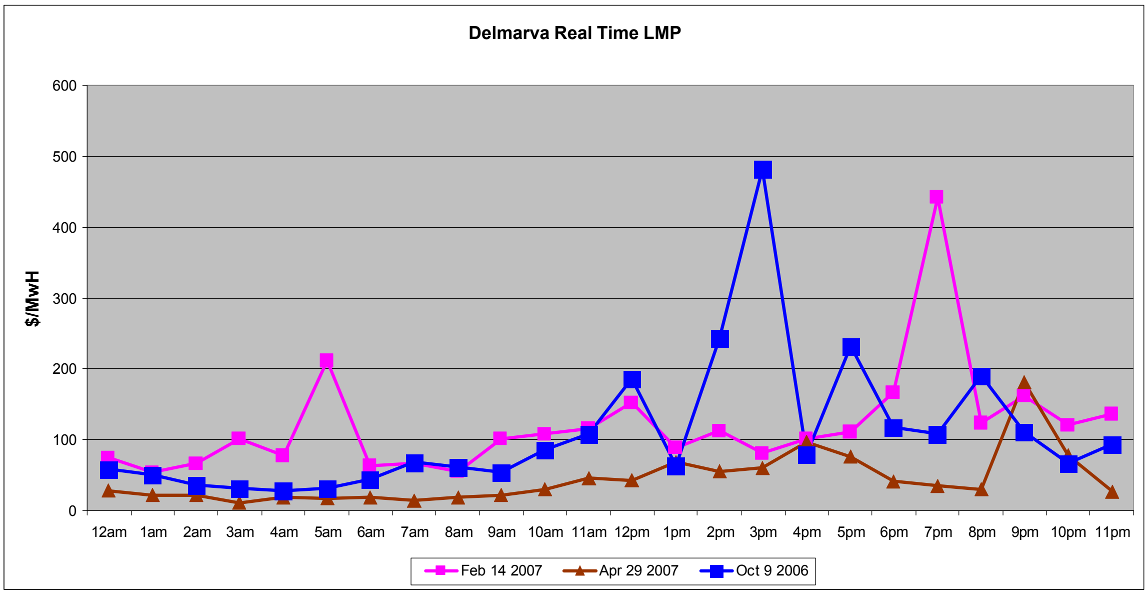
When PJM dispatches generation, it includes in the dispatch price the transmission losses.   These losses represent the amount of energy consumed in delivering electricity from generators to loads across the PJM system. These losses, referred to as "marginal losses," are therefore included in setting the DPL zonal LMP. Including the cost of marginal losses in LMP improves the efficiency of generation dispatch by more accurately representing the true cost of serving locational loads. This, in turn, creates accurate overall system production costs. However, because loads are priced using a marginal loss factor instead of an average loss factor, the resulting LMP will over collect from loads. PJM then allocates this over collection (ie: the difference between marginal and average costs) to transmission customers, including load serving entities, based on their pro-rata use of transmission. Energy portfolios must take account of this "marginal losses" aspect of the energy market.

Historic LMP may not always be an accurate predictor of future zonal LMP. LMP varies considerably as a function of load, available generation and transmission system conditions. As more transmission, such as PHI's proposed MAPP is built it will affect LMP. New demand response, energy conservation programs and new generation resources will affect load demand and have a beneficial impact on LMP.

Delmarva is responsible for supplying its customer energy requirements (MWh) on an hourly basis. Furthermore, this energy needs to be delivered within the Delmarva Zone. To the extent that Delmarva’s energy resources in any hour are “short”; i.e., energy obligations are greater than energy resources, energy will be secured from the spot market for that hour. Likewise, to the extent Delmarva’s energy resources are “long” in any hour; i.e., energy obligations are less than energy resources, energy will be sold into the spot market for that hour. Consequently, managing a resource portfolio that does not exactly equal SOS customer energy requirements in any hour, whether short or long, will result in exposure to the spot market.

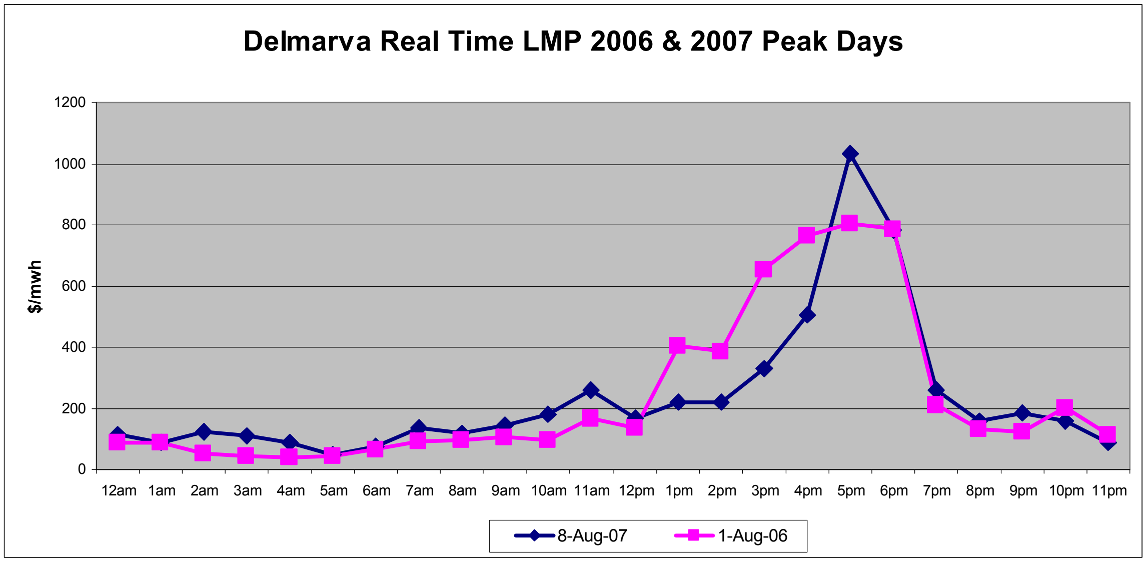
To illustrate the potential volatility of the spot market, Chart RP-5 below shows the hourly LMP for the Delmarva Zone for several different recent historical days.

Chart RP-6



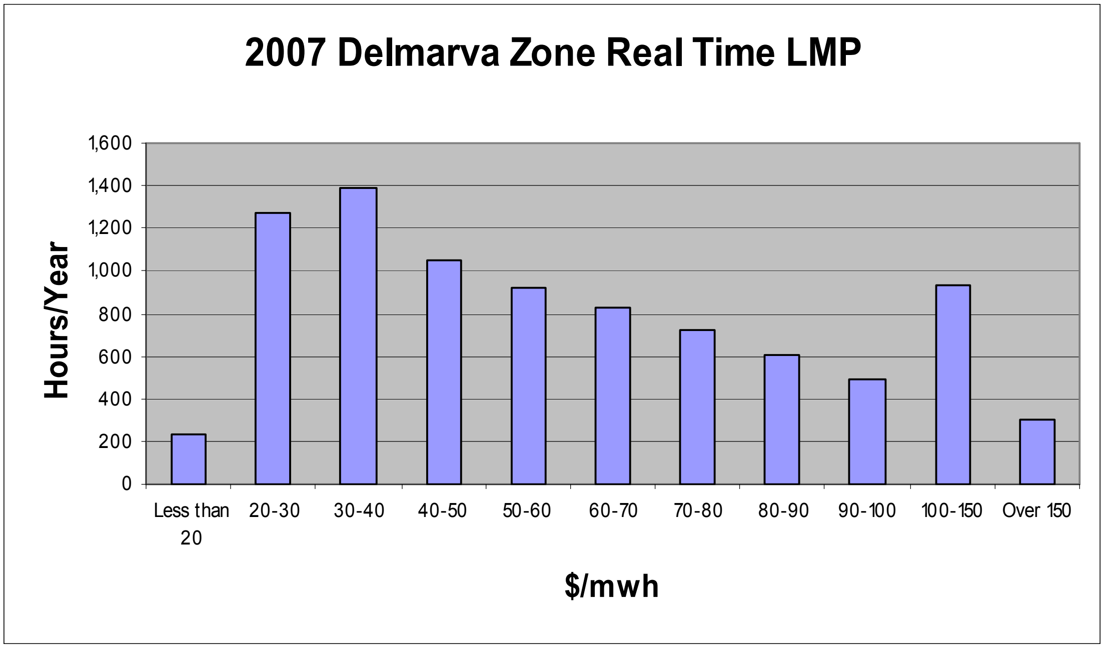
The day of the Summer PJM Zonal LMP peak may be especially volatile. The chart below shows the 24 hour real time LMP profile for the highest LMP days occurring in the PJM Delmarva Zone for 2006 and 2007. The volatility of real time LMP is of concern to a portfolio manager who does not want to be "caught short" in periods of the day where prices may spike.

Chart RP-7_



While the data presented in the two charts above are illustrative of spot market volatility, the spot market may also very well represent some opportunity for customer savings. Chart RP-8 below provides a frequency distribution of the historical hourly Delmarva zone LMP for the 12 months ending December 2007.

Chart RP-8



While the data represented in Table RP-8 is for an historical period that may not be repeated in the future, it does indicate that there have been a significant number of hours where LMP is relatively low (say $50 MWh or less). Consequently, from a portfolio management sense, there may be times when it is advantageous to have some exposure to the spot market if these lower prices can be obtained without undue exposure to volatility.

b. Capacity Markets

Capacity represents the capability of generation to produce electricity, demand side management to reduce load, or even the ability of new transmission lines to deliver energy from area previously inaccessible. By establishing requirements around this capability and requiring load serving entities to acquire specific amounts of it, PJM assures all loads that there will be enough capacity to meet all load in every hour, under all but the most extreme contingency conditions. As discussed elsewhere in this report, PJM operates a Reliability

Pricing Market ("RPM") to clear load requirements and capacity for three years into the future. This RPM market now sets the generator clearing price for capacity and the price load pays for capacity for each PJM planning year (ie: June 1 to the following May 31). The point to be made is that the price paid to generators for capacity is now determined in advance, and fixed by year.

Loads pay for capacity based on the sum of retail customer peak load contributions ("PLC"). Each year, DPL determines the PLC for each customer account following PJM guidelines. Each day, Delmarva determines which supplier of retail load is serving each customer, then sums the PLCs for these customers and reports the total to PJM. Based on the sum of the PLC's, each load serving entity is then assigned a capacity obligation by PJM for that day. Because retail choice allows movement among the load serving entities, the capacity obligation of an individual load serving entity can change daily.

Loads are charged a net load price for capacity by PJM for their aggregated daily capacity obligations, determined by the sum of the PLCs. Loads can enter into bilateral contracts to offset this financial obligation. Loads, for example, might own generation or demand response that offset the area price, effectively sheltering them from the RPM price. In this case, however, the loads would be obligated for all the costs and risks of generation ownership or operation of demand response and would also bear some market risk in the fixed price bilateral contract. The portfolio must balance the assembled assets with the load capacity obligation.

As discussed elsewhere, the RPM clearing market has been in operation for only a short period. It would appear that the intended results are being realized in that more generation, and demand response resources, are being offered. Further, the pricing among the local areas is apparently converging, as demonstrated in the most recent auction for the 2011-12 planning period. This suggests that RPM may provide something of a normalized price signal that will encourage new construction. The RPM price is capped at a price which is a function of estimated costs for construction and revenues from the energy market of a simple cycle combustion turbine generating station. Recent escalation of costs for basic materials such as steel and copper are producing higher estimated installed costs. This, in turn, may lead to higher RPM clearing prices in areas with capacity deficiencies. However, if the estimated installed costs are typical, RPM price, along with revenues from the energy marker, will indeed represent the future cost for any entity to construct the most basic generating resource.

c. Renewable Energy Credits ("RECs")

Delaware law requires each load serving entity to acquire certain Renewable Energy Credits ("RECs"). RECs are associated with energy produced by renewable resource generators, with one REC assigned to each MWh of energy produced. The purpose of the REC requirements is to stimulate construction of renewable resources by providing an additional source of revenue for developers/owners. By creating a *de facto* requirement, the law creates a market for RECs. In fact, by specifying an ascending penalty scale for load serving entities which do not acquire sufficient RECs, the law establishes a benchmark price.

RECs are accounted for through another PJM service where they are registered by generators and then assigned to loads to meet jurisdictional obligations. The quantity of RECs varies with jurisdiction, and with the type of renewable resource producing the REC. For example,in Delaware, there is a distinction between solar resource generated RECs and wind produced RECs.

Load serving entities must report annually to the State, after the end of the compliance year running from June 1 to the following May 31, what RECs they acquired to meet their total annual obligations. There is a period of 120 days between the close of the compliance year and the reporting date in which loads may trade for RECs they need. As the annual requirement increases over the next few years, RECs will become a very significant part of the overall electricity portfolio. Forward contracting for renewable energy and associated RECs may be a reasonable hedge against the exposure of failing to meet the requirements. The Company's recent activities related to acquiring wind related energy and RECs are discussed elsewhere in this report The portfolio implemented by DPL must acquire sufficient RECs to meet the solar and other renewable requirements as they vary annually, and as the underlying load obligation varies annually. Therefore, an active market participation as well as forward contracting may be necessary.

d. Ancillary Services

Ancillary Services is a broad term applied to those additional requirements placed on market participants by PJM in order to assure reliable operation of the interconnected system. These services include regulation, operating reserves, synchronous condensing, and reactive services among other services[19]. All services are required by the PJM Operating Agreement ("OA") or the PJM Open Access Transmission Tariff ("OATT"). In general, the sum of these charges represents a few percent of the total wholesale cost of electricity for load serving entities. The rates are either fixed by PJM's tariff or the manner of determining them is specified. PJM determines the quantities required through various operational, billing and accounting procedures, as thoroughly described in the PJM Manuals. While it may be possible to self-supply or hedge these obligations (for example through generation ownership), in general these are simply services provided by the interconnection and billed monthly to load serving entities by PJM.

The importance within a portfolio of these various charges will depend on the extent to which assets hedge, or portfolio practices create additional charges.

e. Transmission Service

Delmarva purchases network integrated transmission service from PJM for all its SOS customers. The obligation is established in a manner very similar to that described above for Capacity. The price of transmission service is set annually at June 1 through the PJM tariff. The purchase of network service

[19] A complete listing of PJM required ancillary services may be found in PJM Manual 29 pp 8-12.

assures electricity will be delivered to the Delmarva zone by PJM from sources within PJM. The cost of service is included in SOS rates.

If Delmarva in its portfolio were to purchase a capacity resource for use into the PJM or energy from sources outside PJM, then Delmarva would be required to purchase transmission service to deliver the energy into PJM. This service would be firm transmission and PJM network external designated service, but is separate from network service purchased from PJM. Therefore the availability and cost of this service would be factors to be evaluated in any such off-PJM purchase.

4. Potential Resource Options:

a. Market Options

Table RO-1 below provides a summary of many of the physical assets available to meet future energy procurement needs. Table RO-2 provides a similar summary of the more common contractual products available to manage a resource portfolio. The challenge for a portfolio manager is basically to select and continually update and augment as needed the combination of physical resources and contract products that is expected, within reasonable risk guidelines, to meet the energy procurement needs of SOS customers.

As can be seen by a review of the information provided in Tables RO-1 and RO-2, there appears to be no single resource that can unilaterally meet the needs of the resource portfolio. Unfortunately there is no “silver bullet”; all of the resources have positive characteristics and they all have some drawbacks as well. Consequently, in Delmarva’s view, the portfolio manager must seek a complementary balance among the various resources contained in the portfolio in order to limit risk exposure and simultaneously provide SOS customers price stability at reasonable cost and meet the RPS standards.

It is worthwhile to note that one of the resources options that an active portfolio manager has available is the ‘spot market’. The spot market can play an important role in the portfolio as a ‘balancing resource’. Because Delmarva’s current procurement strategy relies on FRS contracts there is no current need for load balancing as this is supplied by the FRS contracts. However, as Delmarva transitions away from the current procurement practice of securing 100% FRS SOS supply contracts to a portfolio approach, there will be a need for turning to the spot market for balancing any differences between real time loads and portfolio resources. There may be times when such reliance on the spot market is advantageous to SOS customers in terms of supply costs but it does create more exposure and volatility.

Table RO-1

Potential Physical Asset Resources

Portfolio Option	Description	Pros	Cons
Base Load Fossil Fuel Generation	These plants are generally designed to be operated 24x7. To obtain economies of scale, these plants are typically fairly large, i.e. > 400MW. Due to their need to be reliable, they are often more expensive to build (as measured by $/kw of capacity), but are often	Typically operating costs are low and plants are almost always economic to dispatch. Can be designed to operate on duel fuels (e.g coal/gas) so can take advantage of fuel markets as well as manage emissions.	Difficult permitting and long construction lead times. Often dependent on single fuel source. Plants need to shut down for periodic maintenance. Due to large size any unexpected outage creates large replacement power risks. Due to ramping limits these plants are generally limited in their load following capability. Within the constraints of their

	the least expensive to run. Most have, or will need to add, significant air pollution control equipment.		operating permits, units can be significant volumetric emitters of pollutants, including NOX, SOX, mercury and CO2. Many base load plants incur high environmental compliance expenses.
Nuclear Generation	Like base load fossil plants, nuclear plants are large and designed to operate 24X7. No new nuclear plants have been built in 20 years – so current fleet is aging.	Typically operating costs are among the lowest available; Recent years have seen very high plant availability and capacity factors; no regulated air or green house gas emissions. Most plants are now owned and operated by a small number of large generation owners who have considerable operating experience.	Very large capital costs, difficult permitting and very long construction lead times. Plants need to shut down for periodic maintenance. Due to large size any unexpected outage creates large replacement power risks. Permanent storage capacity for radioactive spent fuel not currently available.
Hydro Generation	These plants are significant generators in the western US but have only a small presence in the mid-Atlantic region.	Usually the cheapest to run (with zero fuel costs) so often run when reservoirs are at acceptable levels.	Dependent on river levels and therefore on annual and seasonal precipitation. Highly unlikely that new hydro facilities will be built in the mid-Atlantic region.
Gas Combined Cycle ("GCC")	A GCC plant combines a gas fired turbine with a steam turbine. The steam is produced by recovering the heat from the gas turbine exhaust.	Less expensive to build than base load plants, but also more expensive to run due to higher fuel costs. Usually these "mid-merit" plants operate once all base load units are on line. These plants can also be used for "spinning reserve" and voltage support. Generally, GCC plants operate at high cycle efficiencies and low heat rates.	Because these plants experience the extremes resultant from frequent starts and stops, they are more prone to outages. GCCs are generally single fuel plants (natural gas) so their economics are more dependent on natural gas prices and natural gas availability during winter periods of high gas demand. The fuel supply issues can be solved by including oil fuel back-up capability.
Oil/Gas Steam Turbines	These plants use a single fuel or dual fuel to produce steam for turbine generation. Choice of fuel is usually market price dependent. These plants are a variety of the mid-merit plants used as the load increases from baseload toward peaking.	These plants are usually less expensive to build than base load plants but more expensive than combined cycle. These plants were generally built in the 1970's when crude oil prices were low. With proper dispatch planning, these plants can provide a needed fill between the base load coal plants and the "quick start" GCC plants.	Many of the oil fired plants are quite old and require maintenance related to their more infrequent use. In the mid-merit market, these plants are significantly less flexible than the GCC plants. With the higher fuel costs associated with oil and natural gas, these units are significantly less efficient than GCC units..

Peaking CTs	Simple cycle peaking units are the least expensive to build and most expensive to operate. These “peakers” are usually the last to be brought on line by PJM. These units operate on a combustion turbine gas principle without use of steam as the conversion force between the fuel and the electricity as exists in the conventional base load, GCC and Oil/Gas Steam Turbines.	Least expensive to build per installed Kw. Quickest to build from permitting to commercial in-service date. Most flexible in responding to power system demands for starting and stopping. Can be operated remotely – needing personnel only for maintenance. Units are often constructed in remote geographic locations to address peak load reliability issues.	Expensive to run due to fuel type and usually not available to run for extended periods of time due to fuel storage capabilities. Maintenance is often based on number of starts (as opposed to hours of operating time for base load plants).
Renewables (Intermittent)	1. Solar – PhotoVoltaic (“PV”) arrays, usually on residential or commercial roof tops; a “large” commercial installation may be 500kw. 2. Wind – individual on-shore and off-shore wind towers have a capacity of 1 – 3 MW; wind “farms” can range in size from 10 (on-shore) to 600 MW (off-shore).	1. Solar – usually available during high demand periods – hot summer afternoons although production begins to “tail off” during evening peak hours. Generally do not face “NIMBY” conflicts. Relatively easy to install and maintain. Generous tax credits currently available. No greenhouse gas emissions. No fossil fuel consumption. 2. Wind – wind farms provide more potential energy output than solar installations based on current technology; European and North American experience is advancing technology. No greenhouse gas emissions and no fossil fuel.	1. Solar – Expensive – as much as $10,000/kw. Typical installation often designed to serve “native” load – energy output not regularly available to the grid. Requires installation of new metering capability at every site (note: AMI deployment would eliminate this issue). 2. Wind – a) Relatively expensive to build ($2,000/Kw)– especially off-shore ($4,000/kW). Wind sites may be in remote locations and require expensive investments to connect to the grid. b) Favorable wind sites (e.g. ridges along the Appalachian chain) may be in conflict with other uses. c) Intermittent. While wind farms are designed to serve the grid, their unpredictable availability is a significant problem for system operators and portfolio managers. Wind farms often require more traditional (e.g. gas fired CT) backup to create reliable capacity. Further, in the mid-Atlantic region, wind availability is often not coincident with peak load – e.g. wind farm availability is at its lowest during summer peaks. Conversely, their periods of high availability, in the Spring and Fall, are often low demand periods, when energy prices are low. Thus, depending on contract terms, surplus energy might have to be sold at below market prices.)

Renewables (other)	Other renewables are defined at the state level. Typical other renewables include biomass, waste-to-energy and landfill gas.	Typically these plants burn a "renewable" fuel to produce steam. Usually inexpensive to operate due to low fuel costs. These plants operate like more standard fossil plants – i.e. they are more available to system operators for dispatch. (However, some of these plants – e.g. waste-to-energy - might be "must-run" at certain times).	Like other fossil plants, require lead times to site and construct. Fuel availability (and therefore siting opportunities) is parochial. Often require expensive air pollution control equipment.
Utility Owned Generation	All of the above physical resources can be owned by the Utility and subject to regulation by the Public Service Commission. .	Regulated assets are subject to utility accounting and rate of return regulation. All gains from plant operation go to Utility customers. Asset provides benefits to customers over entire useful life not just contract term.	Requires re-establishing a fuel recovery clause or similar mechanism. Potential for stranded cost requires non-bypassable distribution charges and/or restriction of customer choice.

Demand Response	DR Programs are designed to lower energy demand at specific periods-usually associated with peak demand. These programs can be initiated by the utility or the customer. Utility initiated programs are usually designed to turn off high demand units – e.g., central air conditioning condensers, pool pumps – via an electronic signal to a receiving device on the unit. More recently designed customer initiated DR is associated with some form of peak pricing, whereby the customer lowers demand in response to the "peak price" signal.	A number of recent studies have shown that reducing peak demand can have a significant affect of overall energy prices, as peak demand energy is the most expensive, "e.g., see Mid-Atlantic Distributed Resources Initiative Working Group study conducted by the Brattle Group. Customer initiated DR programs have few program costs (the financial benefit to the customer comes from a lower energy bill) – although these programs require the installation of an Advanced Metering Infrastructure ("AMI").	As noted, customer initiated DR programs require AMI installation. In addition, utility initiated DR programs typically provide an incentive payment to participate.
Energy Efficiency	These programs are designed to lower overall energy use through the installation of appliances (e.g. refrigerator) or other asset (home installation) which are designed to be energy efficient.	Energy Efficiency programs can lead to significant long-term energy savings – e.g. the replacement of traditional incandescent light bulbs with compact fluorescents.	Significant savings from EE programs may take years to occur. – e. g. replacing the existing home refrigerator stock with more energy efficient models could take 15 – 20 years.
Transmission	For reliability purposes, transmission capacity (usually defined as 128 kv and above) can be a substitute for local generation.	Transmission capacity is very reliable and allows a region access to generation anywhere on the grid – i.e. transmission can provide access to lower cost and/or renewable energy not previously available in a given region. Transmission planning is conducted at the regional level, has a long term perspective and takes into account planned generation resource retirements.	New transmission capacity must be approved by the regional electric system operator (in DE's case – PJM) and can be difficult to permit and site. As a result construction can be substantially delayed.

Table RO-2
Potential Contract Resources

Contract Type	Description	Pro	Con
Full Service Requirements	Meets all load serving requirements; energy (MWH), capacity (MW), RPS requirement (renewables), ancillary services (voltage support, spinning reserve, etc.). Supplier takes all load following risk – i.e. contract for actual load at each hour, not for a fixed amount . In addition, if customer choice is available to retail customers, supplier takes risk for longer-term load changes –i.e. supplier responsible for meeting load requirement as customers migrate from or to service.	The most complete contract type since supplier is providing the full range of products and taking all risk for short- and long-term load following. Due to the load following requirement, these contracts are usually for a short- to mid-term – e.g. 3 years.	Higher premiums since the supplier is charging for all of the fuel pricing and load following risk.
Firm Service	These contracts are for a fixed amount of energy (and capacity) – i.e. the supplier takes no volume risk. These contracts do not rely on specified generating units.	There is a known price for the fixed volume of energy and capacity.. These contracts can be defined for specific time periods, e.g., peak period only or round the clock.	Since amount is fixed, other arrangements must be made to account for load following and other ancillary products. Firm products may entail premiums over other types of contracts.
Spot Market	The "real time" market. Prices follow the dispatch order – i.e. the last unit brought on line.	A round the clock market, with energy always available. In some hours prices may be relatively low.	Great price volatility – with the potential for very high prices under peak load conditions.
Unit Contingent	An agreement to take energy (and other products) from a specific generating unit.	A known quantity of energy and capacity from a known unit.	Supply restricted to a single unit. Must account for other products and unit outages (planned and forced) through other contracts. Similar contracts were negotiated 20 years ago, as required by PURPA, which did not prove to

			benefit utility customers
Futures & Forward Contracts	1, Futures contracts are contracts to buy or sell an underlying instrument (e.g. electricity) at a certain future date and a specified price. A futures contract gives the holder the obligation (not just the right – see options below) to buy or sell 2. A forward contract is an agreement between two parties to buy or sell a community (electricity contract) at a pre-agreed future point of time. The trade date and delivery date are separated.	Both instruments are used to control risk, for example forward and future contracts could offset the risks of long term contracts by giving the buyer (or seller) the ability to "hedge" such a contract with possible lower (or higher) payments. The forward or future price can be compared to the spot price – see above – and is either at a premium or discount to that price.	Such "derivative" instruments can have substantial transaction costs.
Options (puts & calls)	Options are rights (but not obligations) to buy ("call") or sell ("put") a commodity at a fixed price up to a pre-determined future date (the "expiration" date)	Options can be used to give a seller (or buyer) the right to sell (or buy) a commodity (electricity) at a predetermined price at a future date. Thus, for example, a buyer could have an option to acquire a commodity at a lower price than the prevailing spot price up to future expiration date.	Options cost money to acquire, and can be worthless at the expiration date – e.g. for a buyer, the spot price of the commodity up to the expiration date is lower than the option contract price – so there is no advantage to "exercising" the call option. Such an option is referred to as "out of the money."

b. Long Term Contracts and Resources

Long term contracts and resources can play important roles in a managed portfolio. Longer term resources come in many different sizes and "designs". Consequently, it is difficult to make specific recommendations or even broad generalizations around these types of resources due to the wide range of alternatives they represent. To illustrate, consider the three original bids from NRG, Bluewater Wind ("BWW") and Conectiv Energy ("CE") received in response to Delmarva's RFP of December 22, 2006.

NRG proposed a generation *unit-contingent* contract for up to *450 MW* from a *base-load* Integrated Gasification Combined Cycle ("IGCC") plant to be constructed at the Indian River site. The bid contained options for *20 or 25 year* contracts. The bid proposed a minimum *fixed volume round the clock must take* generation output of 200 MW and the option to take an additional fixed round the clock 250 MW at a lower price. The contract price was tied to coal indices and all additional environmental compliance costs based on any future regulations would be added to the cost.

BWW proposed a generation unit contingent contract for up to *450 MW* of *intermittent energy* to be obtained from an off-shore wind farm. The bid contained options for *20 or 25 year* contracts. The bid proposed a *variable volume must take* generation output which was dependent on wind conditions. The contract price would escalate at a fixed 2.5% per year.

CE proposed a contract for about *175MW* of *firm* (i.e. not from a single source) energy backed by a newly constructed gas powered *peaking* facility. The *fixed volume must take* firm energy was for the *peak period* only and the contract price would escalate based upon a coal price index. The contract term was for *10 years* with an option to extend the contract for an additional five years at the buyer's discretion. All additional environmental compliance costs based on any future regulations would be added to the cost.

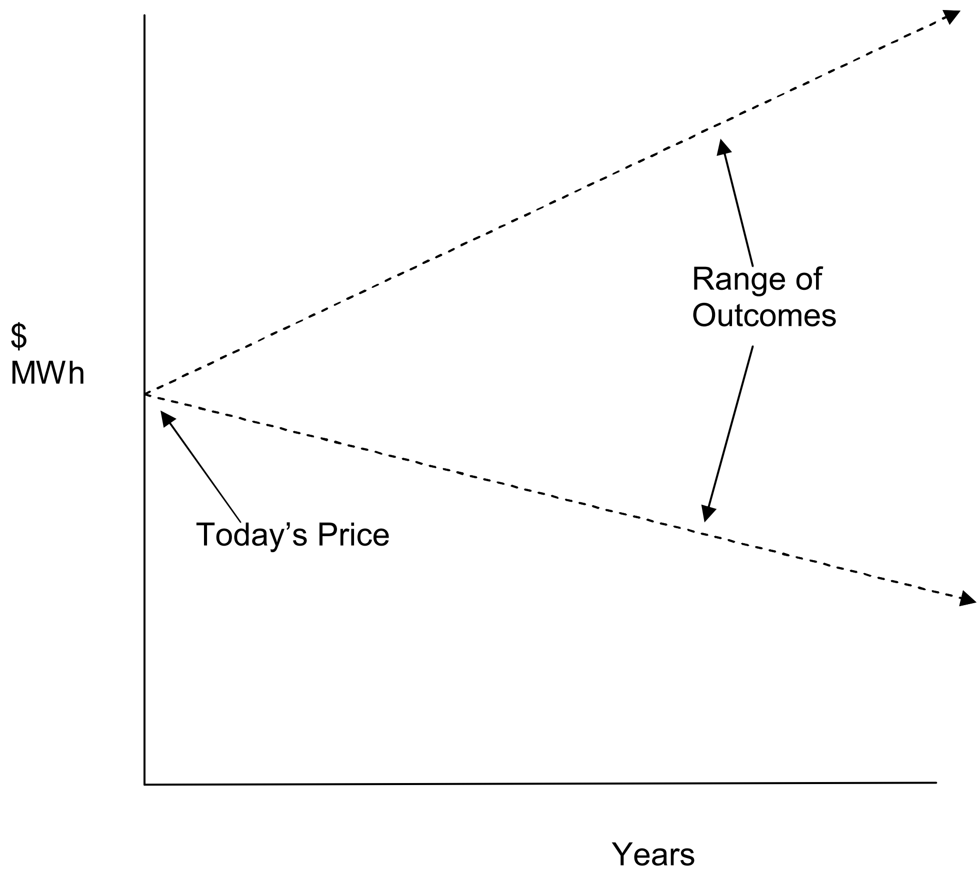
These three bids represent a very wide range of alternatives, but even so do not represent the full range of potential long term resources to include in Delmarva's SOS portfolio. For example, other such resources could include regulated generation assets, long term fuel purchases, various bilateral arrangements with generators inside or outside of Delaware, contracts for RECs, or various forward or future contracts. In any event, it is critical that, whatever long term resources are selected as part of Delmarva's managed portfolio, they are well matched with the electrical load characteristics of SOS customers and the size of the overall portfolio. The remainder of this section on long term resources provides an evaluation and discussion around incorporating long term resources into Delmarva's SOS customer procurement portfolio.

i. Expectations of Long Term Resources within a Portfolio

It is important to consider what the objectives of long term positions within a portfolio are intended to achieve. EURCSA expressed a desire for price stability at lowest reasonable cost. EURCSA also included a desire to "immediately attempt to stabilize the long term outlook for Standard Offer Supply in the DP&L service territory." However, because of the complex nature and the uncertainties associated with customer load requirements and future market conditions, it is difficult to assume, out of hand, that long term resources will necessarily achieve the desired goals of price stability and reasonable cost simply because they are "long term" or have "fixed prices". In order to obtain some comfort that long term resources within a portfolio will achieve the desired ends, it is necessary for the portfolio manager to examine how any specific long term contract obligation might overlay on uncertain future load requirements and unknown market conditions. Some of the more important considerations are discussed below.

ii. Long Term Resources as a Hedge Against Future Price Increases

Power prices vary not only hourly but over longer periods of time as well. Unfortunately a portfolio manager does not know with certainty the direction of long term power prices. To the extent that future power prices can be considered as uncertain or random, a range of possible power prices may occur over time. The range of possible outcomes will increase over time as shown in the figure below.



The goal for a long term resource within a portfolio is to provide stability and hedge against future price increases. If the portfolio manager struck a deal for a long term resource at today's price, then as can be seen from the figure above, there is a chance that prices may rise or fall in the future. Thus the portfolio manager cannot be certain that the long term resource will provide lower prices in the future Consequently the use of long term resources within a portfolio needs to be carefully considered in terms of how much risk and exposure the portfolio can take.

iii. Resource Size and Fixed Volume Requirements

The size of the long term resource obligation in terms of both energy and capacity is of critical importance in how such a resource might fit into a managed portfolio. To illustrate, consider Figure LT-1 below.

Figure LT-1

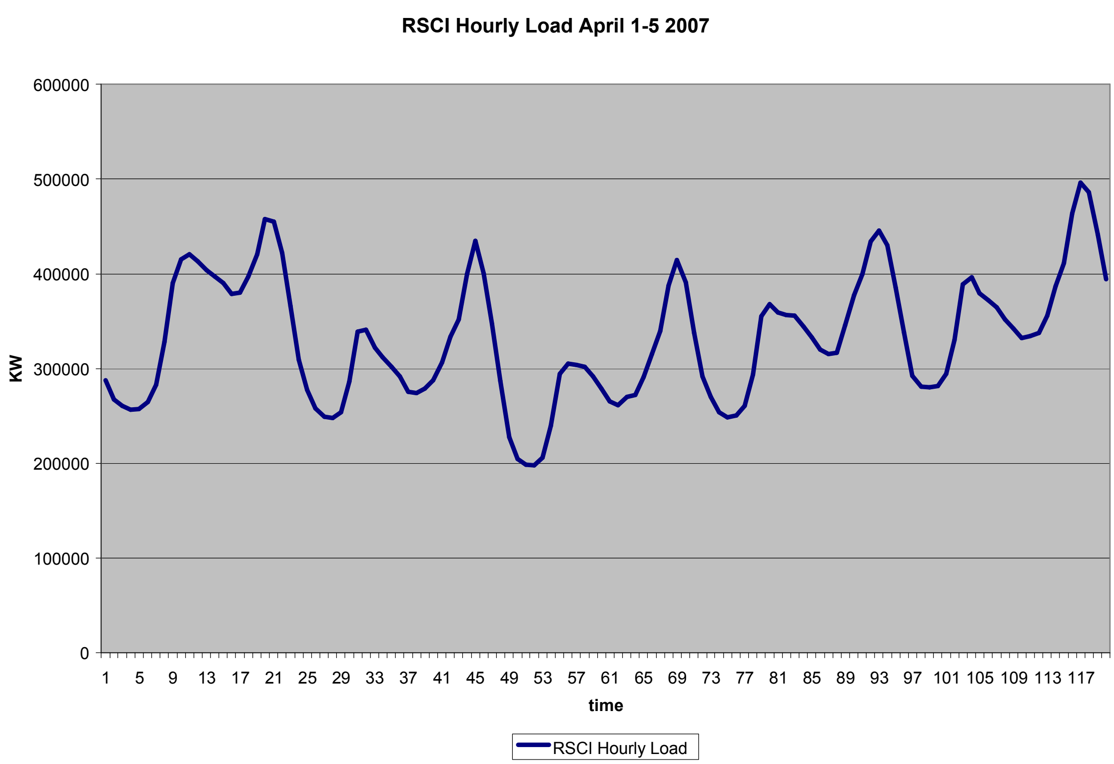
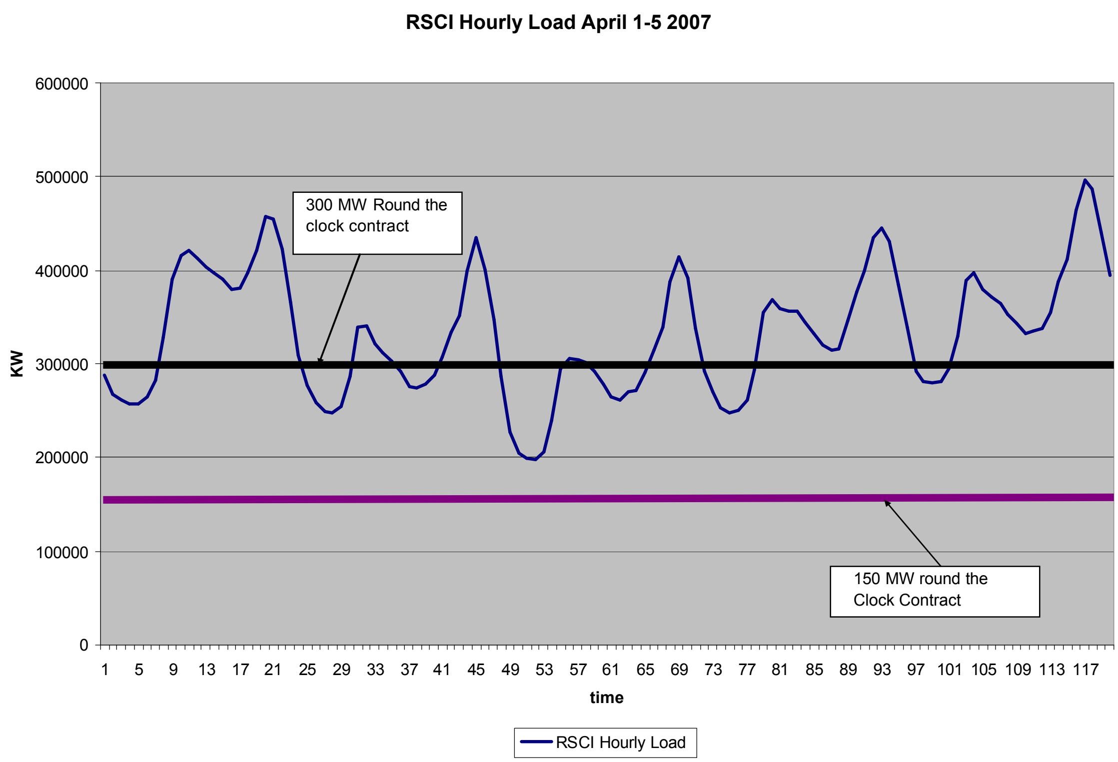


Figure LT-1 shows the actual hourly load profile for the RSCI customer class during the 5 day period April 1, 2007 – April 5, 2007. As can be seen, the RSCI customer load varies over each 24 hour period as well as from day to day. The maximum hourly load over this time period is about 500 MW and the minimum is a little less than 200 MW. Consider now two potential long term fixed volume must take contracts to serve this load: Contract 1, for 150 MW of round the clock energy and, Contract 2 for 300 MW of round the clock energy. These two contracts are shown relative to RSCI customer loads in Figure LT-1a below.

Figure LT-1a



As can be seen, Contract 1 for 150 MW round the clock never exceeds the minimum load of the RSCI customers. In this simple hypothetical instance, a portfolio manager only needs to manage the procurement requirements for the load *above* 150 MW because the fixed volume contract amount is *always below* the amount of load that needs to be procured. All else being equal, Contract 1 is better able to produce stable rates because there is no uncertainty as to what it would cost to secure 150 MW. Customers will pay the same for every contract Mw in every hour and there will be no adjustments or true-ups as a result of the contract.[20] This situation is different for Contract 2.

Under contract 2, there are many hours in which the fixed volume of 300 Mw that must be purchased in every hour is *greater* than the RSCI load for that hour. What to do with the excess MW's is a challenge for the portfolio manager in maintaining price stability. Consider what happens to the *total* cost per MWh to SOS customers based on Contract 2 for those hours when the fixed volume contract amount exceeds RSCI load assuming the RSCI load is equal to 250 Mw. As the Portfolio manager, Delmarva will pay for 300 MWh at the contract price and will need to sell the excess of the contract amount over the RSCI load requirements (300 MWh-250 MWh = 50 MWh) into the market. Whenever the contract price is greater than the market price, the hourly cost of the SOS energy to the portfolio for this hour would be equal to:

$$\frac{(300\text{ MWh} \times \$\text{contract price per MWh}) - (50\text{ MWh} \times \$\text{market price per MWh})}{250\text{ MWh}}$$

It can be assumed that whenever RSCI loads are low, market prices will also be low. In fact, it is generally expected that during these hours the market price will be *less* than the contract price. Therefore, the formula above will lead to hourly SOS prices *greater* than the fixed contract price. Importantly from a portfolio management point of view, this greater hourly price will occur for every hour in which the contract amount exceeds RSCI load and market prices are lower than the contract price.

[20] The contract may have escalation factors or ties to a fuel index which would require annual adjustments

This simple example shows how the size of the contract *relative* to the size of the customer load can be a critical consideration for the portfolio manager.

The example above used two fixed volume round the clock contracts as an illustration of one of the many challenges a portfolio manager might face in operating a portfolio. However, Long Term contracts are not always for round the clock obligations; often they can be for defined periods of time within a day such as the peak period. These types of contracts present similar challenges to the portfolio manager.

iv. Firm Versus Unit Contingent Contracts

Long term contracts can provide capacity and energy on either a *firm* basis or a *unit-contingent* basis. It is important for a portfolio manager to understand the difference between the two as they can have significant impact on a portfolio's performance and cost.

A contract for firm energy and capacity establishes a specific amount of energy and capacity to be delivered at specified times to the buyer and does not rely on any single resource to be in operation to back the seller's delivery. In comparison to a unit contingent contract and from a buyer's perspective, these contracts are less risky because the energy and capacity are <u>firm</u> and must always be delivered under the contract. A firm contract imposes more obligations on the seller and generally results in the seller receiving a premium.

On the other hand, a unit contingent contract relies upon the energy and capacity to be delivered from a specified generating unit (or units). As long as the generating unit is in operation the seller can meet the contract obligations. However, for every hour the unit is operating there is a non-zero probability of equipment failure. In addition, all generating sources require some down time for scheduled maintenance. If the unit backing the contract isn't operating, either because of a breakdown or for unscheduled maintenance, no energy or capacity are available for delivery from the unit and the portfolio manager will take the risk of replacing the capacity and energy at market prices during the time the generating unit is out of service.

If a generating unit is *scheduled* to be out of service,, the portfolio manager can take steps ahead of time to secure replacement energy at forward prices and, therefore, does not necessarily have to purchase replacement power from the spot market during the generation unit outage. A portfolio manager can cover the risk of *unscheduled* generation outages by purchasing a call-option. The call option allows the portfolio manager the right, but not the obligation, to purchase a specified amount of energy and capacity at a predetermined price. (Note that options expire on a pre-determined date).

The additional cost of any forward contract to cover scheduled outage obligations and the cost of call options purchased to cover unexpected generation unit outages would need to be considered part of the cost of the long-term resource when comparing firm vs. unit contingent long term contracts. Consequently, when securing long term resources, the portfolio manager must weigh the relative costs of firm vs unit contingent contracts (including the cost of options and forward contracts to cover unit outages) and how much risk the portfolio can accept.

v. <u>Intermittent Renewable Resources</u>

During the past year there has been much discussion in Delaware around long-term intermittent renewable resources. Intermittent resources, such as wind generation units, create special risk and challenges for active portfolio management. The intermittency of a resource creates additional uncertainty around how much of the resource will be available at any moment in time. This uncertainty is in addition to the uncertain load conditions and market prices faced by a portfolio manager.

One of the better ways to manage an intermittent asset is to incorporate the resource as a "hedge" within the portfolio. Under this strategy, the portfolio manager purchases the intermittent resources capacity and energy output as obligated by contract at the contract price but resells it at market price every hour. This hedge position does not tie the intermittent resource to the SOS load. By not tying the intermittent resource to SOS load, the portfolio manager has effectively resolved the issue of the managing the procurement of the uncertain hourly difference between SOS load and intermittent resource output.

Under the hedge strategy, for every hour in which the intermittent resource is operating, the hedge will “make money” when the contract price is less than market price and “lose money” when the contract price is greater than the market price. Consequently, because of the dual uncertainty of the output of the intermittent resource and the difference between the spot market and the fixed contract price, the total cost to SOS customers for each hour is not “fixed”. This situation also leads to the need for a true-up mechanism to protect both the portfolio manager and SOS customers.

For the portfolio manager, the hedge strategy may also be applied to other long term non-intermittent resources. Whenever hedge strategies as described above are used by the portfolio manager, whether for intermittent or non-intermittent resources, <u>the *net* cost to the portfolio is not fixed, even if the long term contract price for the resource output is fixed</u>. This element of a hedging strategy must be taken into account when determining the portfolio’s ability to provide for “stable” prices.This is just another of the risks that must be managed by the portfolio.

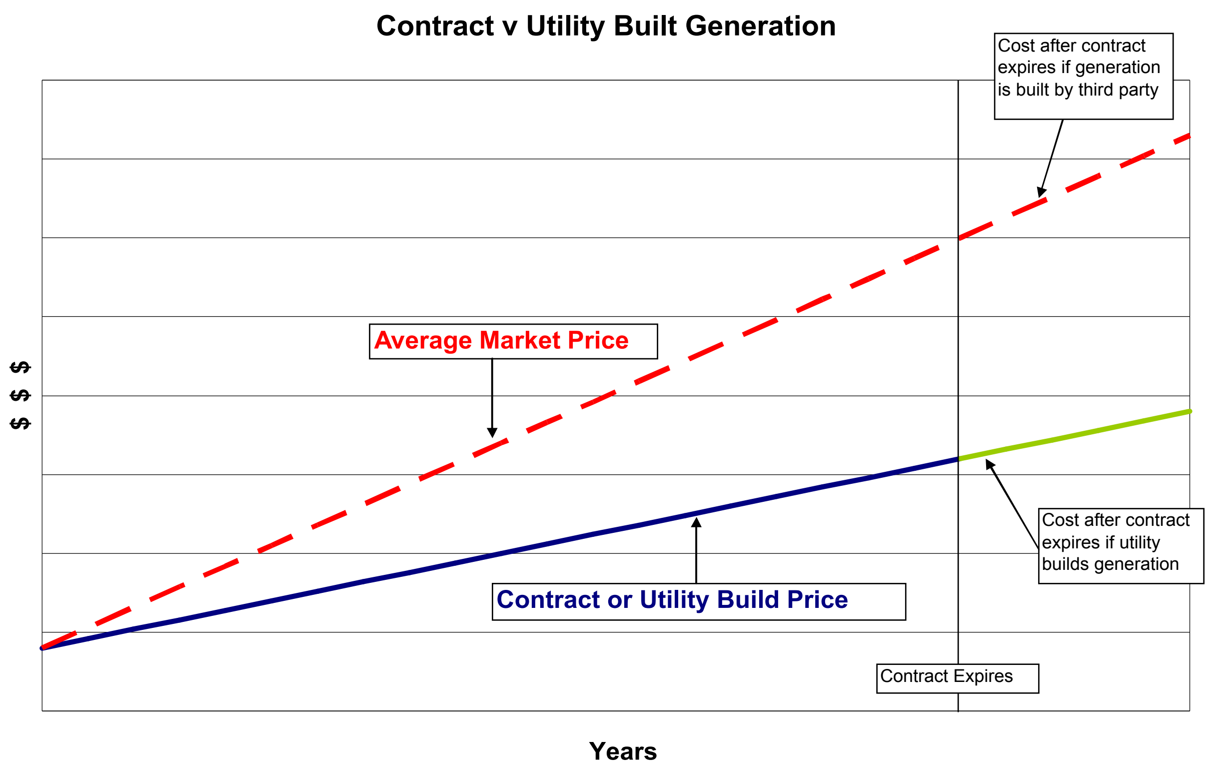
vi. Longer Term Fuel Contracts as Hedges

Because most generation assets rely on commodity fuels as an input in producing electricity, a portfolio manager may be able to hedge forward *power* prices with longer term *fuel* resources. For example, if the portfolio manager believes that natural gas prices will be rising and consequently be translated into higher power prices, then the portfolio manager could take a forward position in natural gas. This forward position could "lock –in" a fixed quantity of natural gas at a fixed price in the future. If gas prices rise, the forward position would become more valuable and the portfolio manager could then sell the position and use the profits to credit and offset other portfolio expenses. Of course, if gas prices fell the opposite would be true and the hedge would create a loss to be absorbed by SOS customers.

In either event, the fuel hedge can potentially dampen the effect of both adverse and positive fuel price movements. Fuel hedges have long been encouraged by Commission Staff and used by Delmarva's Gas Division to help manage the volatility of delivered natural gas prices.

vii. Regulated Generation Assets

Among its many provisions, EURCSA provided the Commission the ability to authorize the utility to own or build generation assets. While regulated generation assets may be similar *physically* to generation assets obtained through long term contract, the *financial consequences* and *benefits* to customers can be markedly different between the two types of resources. Many of the benefits of utility owned generation from a customer perspective are discussed in the reliability section of this IRP[21]. A large potential advantage of utility owned generation assets relative to long term contracts is based on comparing what could happen to the prices paid by customers at the end of a long term commitment especially if at the termination of the contract market prices are higher than the long term contract price. This situation is shown in the chart below.



The chart above shows the situation where the contract (or utility) price is less than the market price as time goes on and the end of the contract approaches. As can be seen under a long term contract approach, at the end of the contract term the plant will be turned over

[21] As noted in that section, the construction and operation of regulated generation assets in Delaware may provide additional reliability and economic benefits to customers. Delmarva would be willing to construct and operate a regulated generation facility in Delaware for purposes of further securing reliability and other customer benefits under either traditional regulation or its functional equivalent.

to the unregulated supplier which will then be free to charge the market price for plant energy. Delmarva's customers will have borne the risks of financing, building and operating that plant during the contract term, but, after the term expires, all the economic benefits going forward will be realized solely by the plant's owner.

In the alternative, if the utility builds new generation, the economic benefits stay with the customers throughout the entire life of the plant. Those who are bearing the risks of financing, building and operating the plant now receive all of the benefits of taking on that risk.

As discussed elsewhere within this IRP, whether the Commission requires Delmarva or an unregulated supplier with a long term contract to build new generation, the reality will be that customers will have to pay for this generation. This means that either the Commission should require customers to pay a non-bypassble distribution charge on their bill or customer choice should be restricted.

5. **Portfolio Risk Management for Standard Offer Service ("SOS") Procurement**:

In order to illustrate some of the risk management issues related to actively managing a resource portfolio, Delmarva Power and Light (Delmarva) contracted with The Brattle Group to prepare the following discussion and analysis. The Principal at The Brattle Group responsible for directing this project is . FrankGraves, a recognized expert on power procurement and risk management.

The purposes of this discussion are three-fold: First, there is a general description of several of the economic and engineering aspects of the problem of portfolio procurement for a Standard Offer Service (SOS) obligation under acceptable risk limits. Second, there is a presentation of the results of some simulations showing how several hypothetical, somewhat simplified portfolios might perform in the fall of 2008 and most of 2009. These are based on current PJM and Delmarva market data. They are intended to begin to demonstrate the extent of risk that Delmarva and its SOS customers are facing and how those risks can be mitigated in different ways. Finally, the report explains a collaborative process that Delmarva recommends for going forward to reach agreement on the goals, procurement procedures, and performance evaluation criteria that should be used if Delmarva is to cover its future SOS obligations under a portfolio management approach.

a. Elements of Portfolio Procurement and Risk Management

The supply portfolio procurement problem facing Delmarva or any SOS supplier is a complex one. There are several kinds of uncertainty that must be anticipated and several kinds of constraints on the possible solutions that must be recognized. The key uncertainties are:

- future load levels and shapes (which in turn depend on how many customers have switched to or from 3d party retail suppliers and other factors like weather),
- power prices in the spot and forward markets,
- the prices of PJM services and obligations, such as ancillary services, congestion, and RPM capacity,
- construction costs and fuel prices and volatility, if physical assets are to be part of the portfolio composition.

In the simulations presented herein, the focus is solely on the energy price uncertainty aspects of providing SOS service. Important related problems of non-energy supply components, procurement processes, credit management, pricing of the SOS service, and customer switching rules are not analyzed, though some of their interactions with energy price risk are mentioned. These other problems should be addressed once there is a common understanding of the energy price-risk problem and the opportunities for managing the SOS portfolio.

A first step in portfolio planning is to have forecasts of these factors, as well as measures of their uncertainty, expressed as possible future price ranges along with their associated probabilities and correlations among the factors.[22] To the extent possible, this information should be taken from the wholesale power and financial markets, rather than from fundamental forecasts, because market prices reflect conditions under which parties will actually trade. Once these parameters are quantified and formalized as mathematical expressions, they can be used to project possible future costs of alternative supply portfolios across a very broad range of specific market circumstances that could unfold.

In general, the total risk of the SOS supply problem cannot be reduced or eliminated. However, it is possible to control who incurs certain risks along the supply chain -- albeit often at some expense. For instance, load uncertainty is inevitable, but its costs can be made entirely the burden of upstream suppliers in exchange for a risk premium (as in the current full-requirements, vertical tranche auction), or be buffered at the utility level (in a balancing account for capturing and eventually amortizing differences between costs and rates), or be passed downstream fully and rapidly to customers (in a flowthrough clause, thereby increasing customer risk but avoiding a risk premium in the average price of supply for that problem). There is no "right" or *per se* dominant answer for where the best place is to assign and compensate risk. This is a matter of risk tolerances and of the ancillary consequences to the parties from being exposed to risk. This means that portfolio management objectives and the resulting preferred portfolio cannot be chosen solely on its face, but must be sorted out among Delmarva, the Commission, and its customers. A supply strategy should

22 Correlation is a statistical measure of the extent to which uncertain factors tend to change in the same direction.

be selected that conforms as closely as possible to their risk tolerances, financial capabilities, and administrative abilities to implement and monitor the design.

The goal of SOS portfolio procurement and management should be to achieve a specified range of acceptable risk, not to try to "find bargains" or "beat the market." In efficient and liquid markets, there is a specific trade-off between price and risk, such that the risk-adjusted cost (*i.e.*, the expected present value) of two different portfolios should be virtually identical, if transaction costs are sufficiently low. Electric power markets, such as the trading of energy at the PJM hubs, are markets where many sophisticated players participate and closely monitor relative prices of different products. One would not expect such markets to be susceptible to sustained periods of mis-pricing across products of different durations and risks. If there was any material mis-pricing, traders would step in to buy the relatively low-priced product (*e.g.*, an under-priced forward contract) and re-sell that product into the market in another form (*e.g.*, as spot power). Under this kind of competitive pressure, prices should reflect the underlying market conditions affecting the products.

Because the primary goal of portfolio management is procurement of supply at an acceptable price and risk, it is not possible to state categorically what supply elements a desirable portfolio should include. That question can only be answered with a clear understanding of the underlying needs and constraints facing the customers and SOS provider. Reaching that understanding generally requires a process of exchanging information about the risk management alternatives and comparing how they would satisfy the affected parties. However, experience in other SOS resource planning settings suggests that a typical goal is to achieve reasonable rate stability while staying roughly in line with wholesale market prices over a two- to three-year horizon. It appears to be generally the case that customers and regulators want to manage both "risk" and "regret". Risk is the *a priori* exposure to future uncertainty. It is reduced through hedging and transfer of risks to suppliers, so that future service prices and terms are more certain and knowable in advance. Regret is the *ex post* exposure to disappointment from having a higher resulting SOS price compared to some alternative strategy (known only in hindsight to be attractive) that might otherwise have been pursued. It is impossible to simultaneously minimize both risk and regret. The best one can do is to balance them against each other, so as to not be unduly vulnerable to either future risk or to the hindsight possibility of unfortunate market timing. With that tradeoff in mind, a desirable portfolio could include some of these elements: (i) forward purchases of perhaps 2-3 years in length; (ii) shorter term installment purchases staggered over time; and, (iii) some reliance on the spot market.

- Two-to-three year forward purchases at a fixed price and volume can be used to cover "baseload" needs and reduce the seasonal variability of portfolio costs. Such purchases transfer price risk to the seller, but they are exposed to potential credit problems and *ex post* regret. Since these contracts are sizable and long-term, the market position of the counter-party supplier can grow rapidly "out of market" if wholesale electricity prices subsequently rise, making bankruptcy risk and the inherent replacement energy price risk a legitimate concern. This "counter-party risk" can be reduced but not eliminated by using multiple suppliers.
- Staggered purchases, such as a buying for a portion of next year's needs in installments over the preceding months, is sometimes also referred to as "dollar cost averaging," analogous to the personal investment strategy of buying steadily over time. This pattern of procurement helps to mitigate "regret risk"; by spreading out multiple forward purchases over time and across several parties, the impact of any single inopportune purchase is lessened and

counterparty risk is diversified. Of course, the opportunity to have inadvertently bought all of one's needs at a fortuitously low price is also foregone, and the *a priori* uncertainty in future prices is kept open for longer, creating more price risk, but that is always the tradeoff if one wants to avoid regret.

- Spot purchases for a modest portion of total needs are desirable, due to unanticipated variations in load due to weather and customer switching to and from competitive retail suppliers. Covering this volumetric uncertainty with spot supplies avoids the risk premium that would otherwise accompany asking a supplier to bear that risk over time at a fixed price, thereby lowering the expected, long-run average costs of the portfolio somewhat – though at the expense of having customers bear some level of market risk. Spot market purchases significantly reduce exposure to counter-party risk.

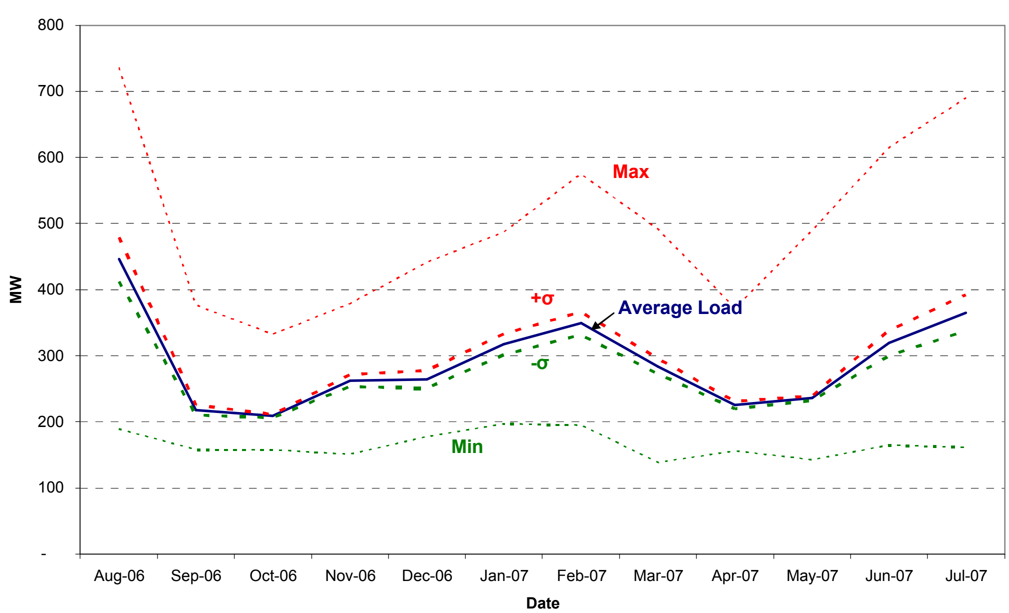
b. Analysis of Demonstrative Portfolios

To demonstrate the effects of alternative portfolio designs on SOS price risk, a series of portfolios of increasing complexity were simulated. These simulations examined relatively simplified portfolios consisting of just forwards purchased all at once or purchased in installments over time, just spot, or blends of both fixed-price, installment, and spot purchases. These simulations pertain only to the cost of energy and congestion delivered to the Delmarva Zone. They do not include the costs of ancillary services, losses, capacity, PJM service charges, the effects of FTRs, or other elements that will be part of the total retail cost. Some of those missing elements are amenable to inclusion in this type of analysis, but they have been omitted here for the sake of simplicity and clarity in explaining the effects of energy risk management.

The simulations are also simplified as to the time scale over which costs are incurred and demands are realized. Specifically, the modeled delivery periods are entire months, with no daily or hourly considerations other than how those time frames implicitly affect average monthly prices, monthly volatility and average load uncertainty. The analysis also does not include the impact of any potential customer switching on load volatility. Finally, the time value of money is also ignored, and all costs are expressed in nominal dollars. These simplifications have been made to allow a clearer demonstration of the risk management implications arising from just the time pattern and horizon of supply purchasing. They have not been omitted because they are of secondary importance; they are important and their exclusion should be remedied before any final policy judgments are made about how to design and administer Delmarva's SOS portfolio.

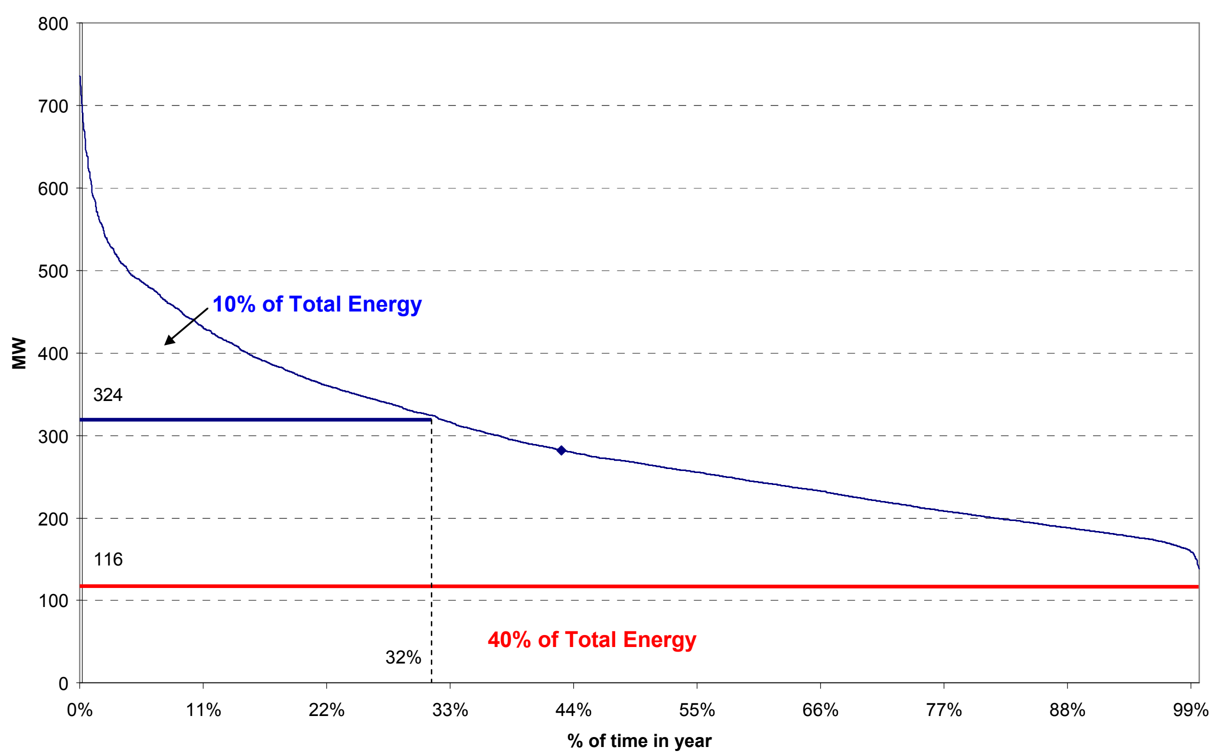
The average historical hourly load levels (by month, in MWs) for Delmarva and the associated typical weather uncertainty considered are shown in Figure 1 below.

Figure 1: Average, Min and Max DPL Peak Hourly Load for Residential and Small Commercial Customers



This figure reflects only the load during on-peak hours for residential and small commercial customers as experienced over the 12 months beginning August 2006. This data has been scaled to 70% of those customers' total needs, because 30% will be supplied by FRS contracts per EURCSA requirements. Note that the average load is around 300MW, while the minimum hourly load is around 150 MW. This means that annual or staggered forward contracts up to around 150 MW could be used to serve the base-load portion of total needs. The weather uncertainty surrounding average monthly loads is not very large, a few percent.[23] Maximum hourly loads in each month can be almost two times the average, but those occurred in relatively few of the hours in a month, making it more appropriate to cover them with spot purchases. This is more easily seen when viewing the hourly load levels, reordered from highest to lowest as an annual "load duration curve" shown below.

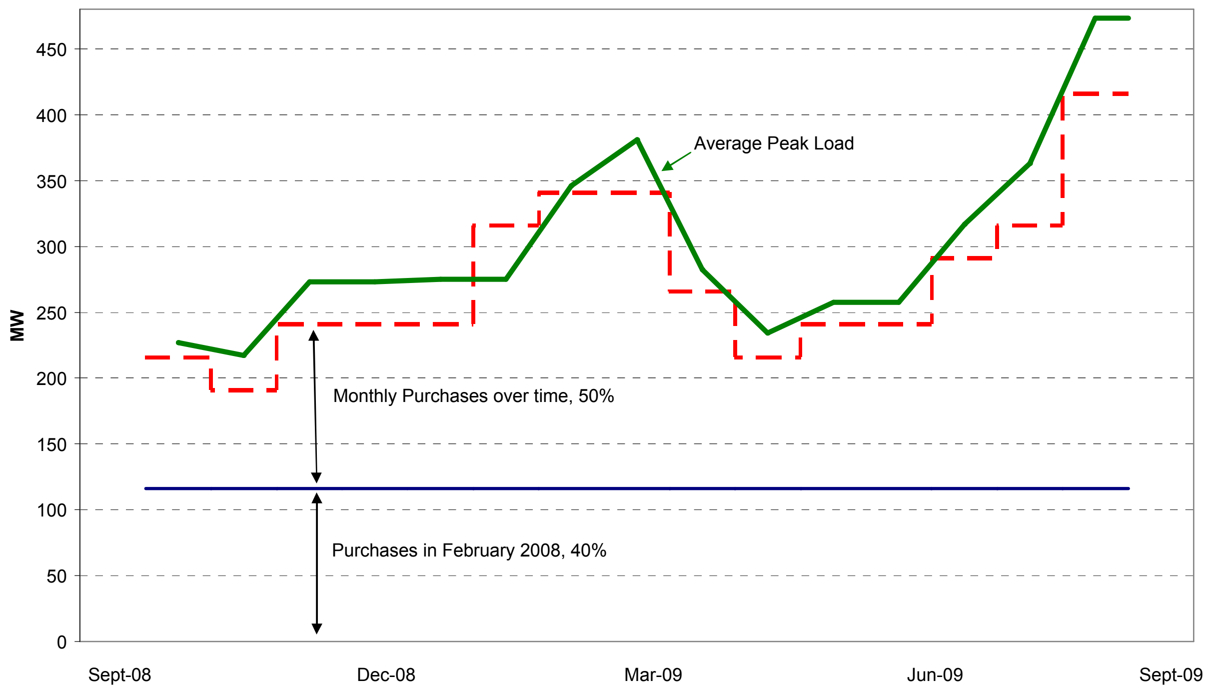
Figure 2: On-Peak Peak Load Duration Curve: 8/06-7/07



[23] The weather uncertainty simulated here is not specific to Delmarva, but is realistic for utilities in PJM. Daily and hourly weather uncertainty, not reflected in this analysis, would be much larger.

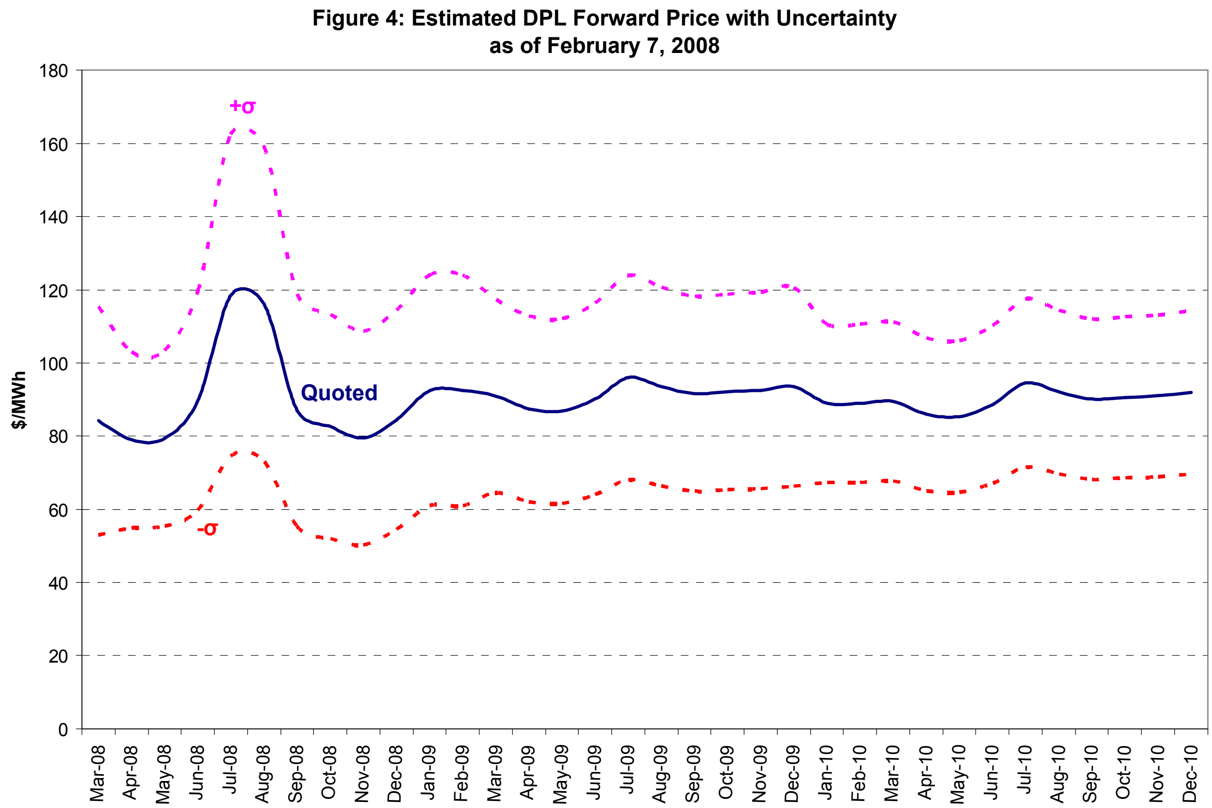
The horizontal lines in the above graph indicate how large a baseload contract would have to be in order to provide 40% of the total on-peak energy needs of these customers, and for this example how many spot purchases would satisfy the top 10% of total needs. The balance could be satisfied with staggered purchases of monthly forwards. Such a composition is shown below. Unlike the foregoing graphs, this one uses projected loads for the twelve months beginning September 2008. This is the time frame used for simulated future portfolio comparisons.

Figure 3: Possible portfolio layers shaped to match seasonal load (September 2008 to August 2009)



The above provides a possible starting point for an SOS portfolio design, but it would have to be vetted and refined to achieve acceptable risk limits to all the affected parties (as discussed later in this report).

The key input to portfolio planning is of course the expected prices and uncertainty associated with future power purchases. Market outlooks for both of these can be obtained from broker quotes for forward on-peak monthly transactions. As of February 2007, the estimated forward curve at Delmarva looked like:[24]



In this graph, the dark blue line is the on-peak monthly price of power as it was being offered on February 7, 2008 corrected for estimated Delmarva to PJM-West congestion. The dashed lines above and below depict the ranges around those forward prices that brokers believe describe the uncertainty as to what actual average monthly spot prices could turn out to be. Like the monthly forward price, the monthly uncertainty has a pattern of seasonality, being greater for certain months, as well as having a tendency to dampen over time. Those probability ranges were obtained from brokers, who in turn infer them from the price of call option contracts trading for those future delivery months. The price

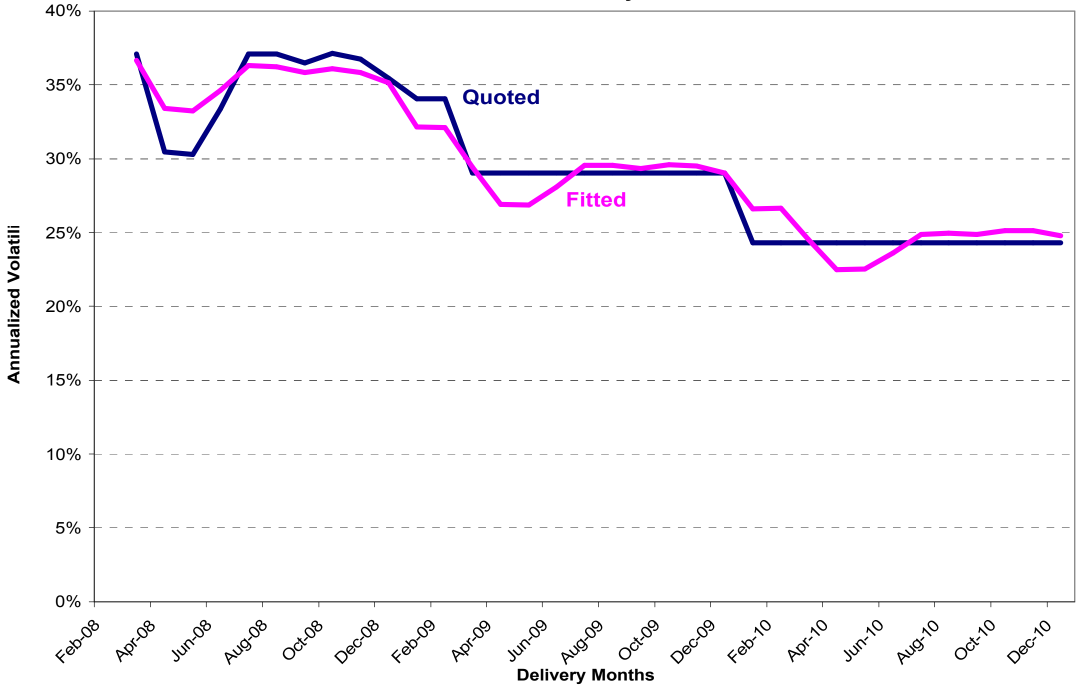
[24] The Delmarva forward curve was estimated by adding the 2006 and 2007 average monthly day-ahead spot market congestion costs from PJM West to the Delmarva zone to the quoted February 7, 2008, PJM West forward curve.

of an option depends on the volatility of the underlying commodity or security upon which the option is based. That is a key element of the well-known result obtained by Black and Scholes regarding the appropriate option price. Accordingly, the price of traded options can be "reverse engineered" to calculate the volatility in a future delivery period that is implicit in the corresponding option price.

The expected volatility of energy prices differs depending on what delivery month is being considered, as well as on when it is being considered, i.e. on how far one is looking into the future. This must be taken into account when simulating how a series of prices for "dollar cost averaging" purchases occurring in installments in future months may change relative to today's prevailing forward prices. To do this, a statistical model is fitted to the volatility quotes to obtain a price volatility function that can be used for any given purchase date and delivery period in the future. The results are shown below in Figure 5.[25] This function is used to simulate how forward prices for power may change between now and future procurements, and what degree of uncertainty to expect in average monthly spot prices for power in the delivery month (for the portion of load covered by spot).

[25] Note – these volatilities are somewhat different than what is normally observed, having too long a short-lived component and too little a long-term component. More typical volatilities would result in somewhat smaller risk ranges for the simulated portfolios.

Figure 5: Volatility Term Structure Fit as of February 7, 2008



Volatility Parameters with Delivery Seasonality

Short Volatility	Short Mean Reversion	Long Volatility
39%	48%	0%

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1.00	1.02	0.95	0.88	0.89	0.95	1.02	1.03	1.04	1.07	1.08	1.08

Using the forecasted prices and associated price volatility function, the simulation model then randomly “draws” a set of future forward and spot prices that will be pertinent for the relevant purchase dates in the future.[26] Using the load volatilities, the loads for each month are also “drawn” by the simulation model, so that the required quantity of spot purchases can be calculated. For each price-load draw, a calculation is made of the resulting portfolio costs.

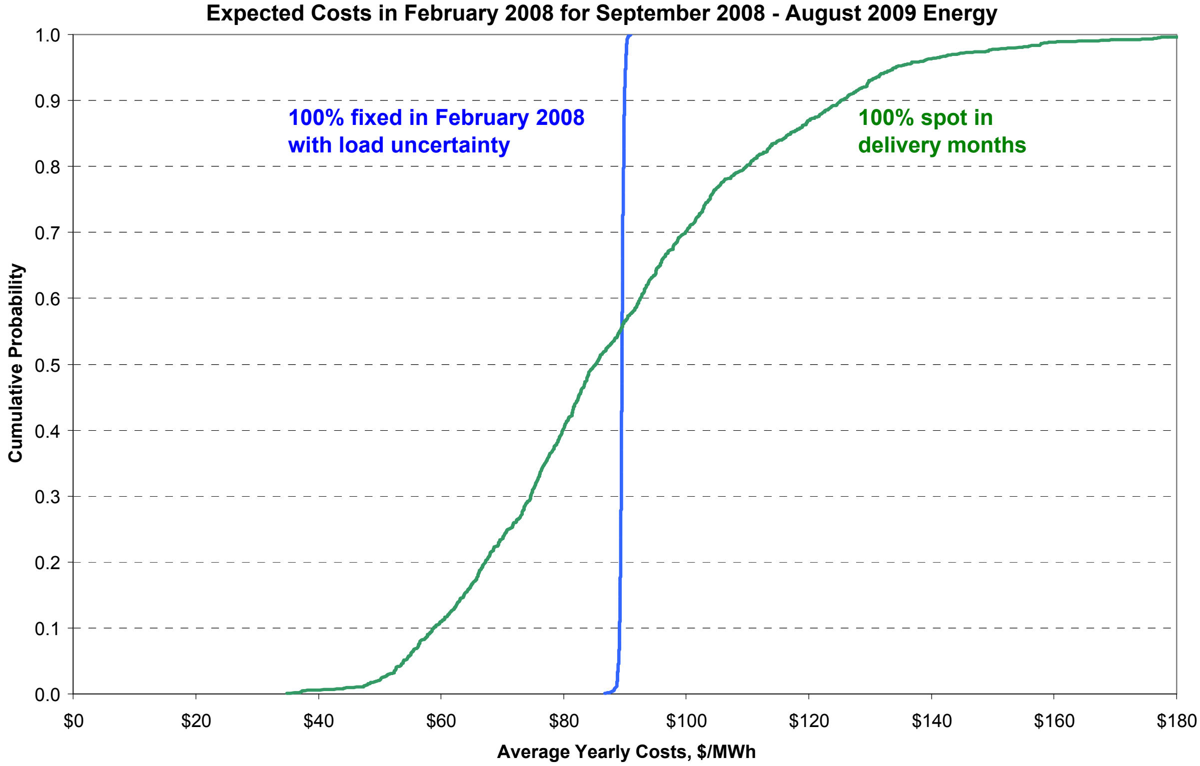
The simulation model repeats the draws over and over (1000 times in this case) to obtain a set of projected outcomes that span the likely range of possible costs in each future delivery period. The riskiness of the alternative portfolios can then be visualized and compared in graphs depicting the range of potential delivered costs along with their associated probabilities.

26 This simulation method is called “Monte Carlo” simulation.

c. Results for Illustrative Portfolios

The simplest portfolios to understand are often the most extreme: either buying all of expected needs in advance in one lump-sum purchase, or leaving all needs “open” initially and buying them at spot in the delivery month, when load actually arises. The former has the least degree of price risk, because it locks down virtually all of the cost well in advance. Not quite all of the cost is locked down, because of weather uncertainty and other forecasting risks that will be borne at the time of delivery, resulting in some degree of total cost uncertainty. The supplemental buying and selling to cover these load uncertainties will occur at then-prevailing spot prices. In contrast, an all-spot strategy eliminates the monthly volume risk but it leaves the price risk entirely open, and so it has the widest possible range of foreseeable costs. When probabilities are associated with these prices, the graph of possible outcomes looks like an S-shaped curve, as seen below in Figure 6.

Figure 6 : Comparative Risks of One-Component Procurement Strategies
Expected Costs in February 2008 for September 2008 - August 2009 Energy



This graph shows the range of potential annual average costs per MWh of the portfolio on the x-axis and the probability of the portfolio having a given cost or lower on the y-axis. The two portfolios shown here reveal the sharp contrast between the low uncertainty under a 100% fixed-cost supply all purchased at once (the almost straight vertical line) and the extreme uncertainty if all needs are met with spot supplies purchased during the delivery period. If all of the September 2008 through August 2009 needs were purchased in February 2008 the cost would have been very close to $90/MWh, with only slight chances of annual average costs per MWh that are a bit lower or higher (due to average monthly load uncertainty from weather). In contrast, the wide, S-shaped curve for spot purchasing spans a huge range, with some low probability of very low prices (down near $40/MWh), an average ($50^{th}$ percentile) price that is the almost the same as the $90/MWh for the all-fixed portfolio, and some chance of very high prices as well ($160/MWh or more). The gap between this spot curve and the left-hand side of the nearly vertical line measures the expected potential for "regret" if all fixed purchases were used. That region depicts the currently foreseen possibility of delivered prices turning out to be lower than the costs that would have been incurred if all expected needs had been contracted in February.

A typical goal of SOS risk management is to design a portfolio procurement strategy that achieves an intermediate profile between these two extremes, *i.e.,* that involves less risk than an all-spot strategy and less potential regret than an all-fixed, up-front purchase. One way to achieve this is to blend the two approaches and to include some forward purchases made in installments. A simple and widely used installment schedule involves starting several months, perhaps six, before the delivery date, and buying a corresponding fraction of the future months up until the delivery date, e.g, one-sixth of each of six delivery months purchased each month. One can vary this basic scheme by starting farther in advance (buying $1/12^{th}$ of monthly requirements in each of the 12 months prior to delivery), buying at less frequent intervals (*e.g*, 1/4 every quarter), and so on. The choice will depend on how it affects the resulting distribution of costs, and also on how it affects the financial health of the buyer to commit to those purchases in advance and then face possible credit calls to cover them, if they should become "out of the money" over time.

Two different schedules for installment purchases were analyzed, one of which would buy each month's needs in the delivery year in six prior monthly installments (the "6 X 12" strategy) and the other that would also buy six months ahead bur for only half a year at a time (6 X 6). It is useful to summarize the proposed purchasing schedule in a matrix that allocates each month's needs to particular purchasing dates. This is shown in the following tables in Figures 7 and 8.

The matrix in Figure 7 is for the 6 X 12 procurement schedule, for 100% of the requirements (no spot or up-front February purchase). Purchasing dates are in the first column and delivery months are shown starting in the third row on the picture. Each cell contains a monthly energy installment purchase rounded to 25MW block purchases. For instance, the purchase in March of 2008 for September 2008 delivery is for a total of 16,800MWh (which is two 25-MW blocks, times 16 on-peak hours per day, times 21 peak days in that month). Note that fixed/standard block sizes generally cannot be combined to add up to precisely the expected load. The error is assumed to be covered with spot purchases (or sales).27

Figure 7: 6x12 Procurement Schedule

Monthly 25MW Blocks	8400	9200	7600	8800	8400	8000	8800	8800	8000	8800	9200	8400
Number of Installments	6	6	6	6	6	6	6	6	6	6	6	6
Purchase Dates	**Sep-08**	**Oct-08**	**Nov-08**	**Dec-08**	**Jan-09**	**Feb-09**	**Mar-09**	**Apr-09**	**May-09**	**Jun-09**	**Jul-09**	**Aug-09**
2/1/08	-	-	-	-	-	-	-	-	-	-	-	-
3/1/08	16,800	9,200	15,200	17,600	16,800	24,000	17,600	17,600	16,000	17,600	18,400	25,200
4/1/08	8,400	18,400	15,200	17,600	25,200	16,000	17,600	8,800	8,000	17,600	27,600	25,200
5/1/08	16,800	9,200	7,600	8,800	16,800	24,000	17,600	17,600	16,000	17,600	18,400	25,200
6/1/08	8,400	18,400	15,200	17,600	16,800	16,000	17,600	8,800	16,000	17,600	27,600	33,600
7/1/08	16,800	9,200	15,200	17,600	25,200	24,000	8,800	17,600	16,000	26,400	18,400	25,200
8/1/08	8,400	18,400	15,200	17,600	16,800	16,000	17,600	8,800	8,000	17,600	27,600	25,200
Total	75,600	82,800	83,600	96,800	117,600	120,000	96,800	79,200	80,000	114,400	138,000	159,600
tal Open including Rounding	644	(2,877)	(583)	(11)	(1,449)	1,977	2,455	3,285	2,394	(2,822)	(4,377)	(609)
Peak Residential Volume	76,244	79,923	83,017	96,789	116,151	121,977	99,255	82,485	82,394	111,578	133,623	158,991

27 The standard trading block size in PJM is typically 50MW; 25MW blocks were used in these examples for illustrative purposes. Purchasing schedules must eventually be constrained to reflect standard block sizes (e.g., 6x12) for only a fraction of total needs and may not be feasible with 50 MW blocks.

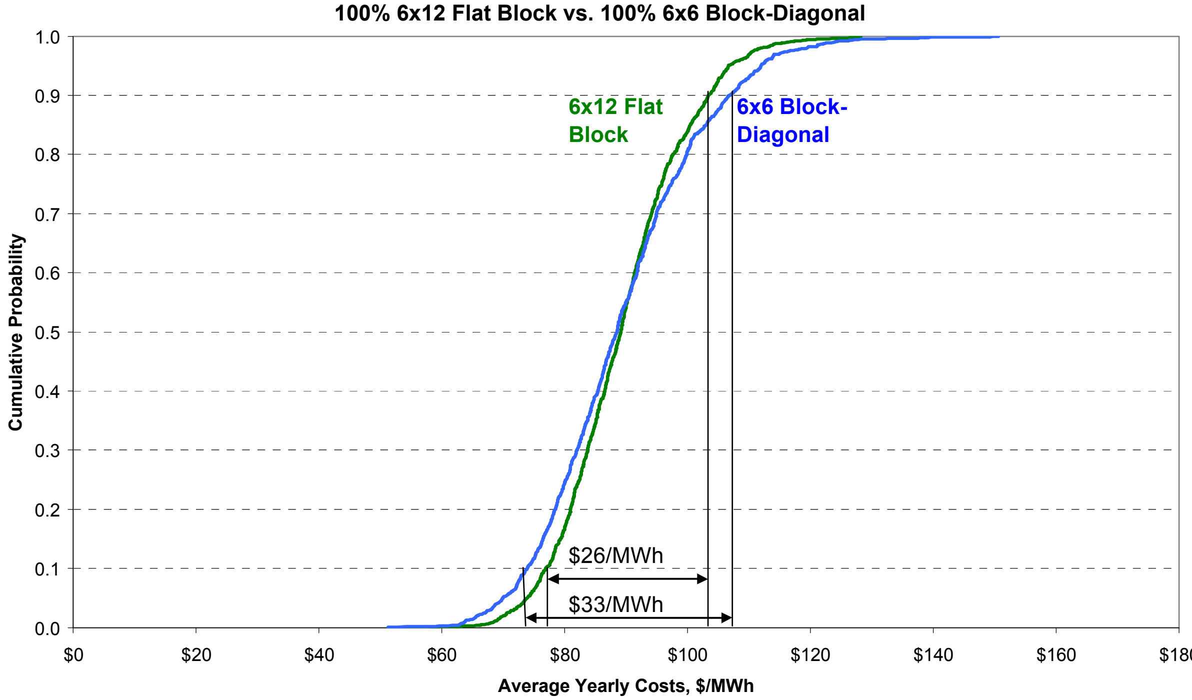
The next matrix is a procurement schedule that covers only 6 months of needs per monthly procurement installment. The same total monthly amounts are obtained as in the 6 X 12 schedule above, but here they eventually (by March 2009) are from purchases made later in time, and closer to the delivery date, than under the 6 X 12 schedule.

Figure 8: 6x6 Procurement Schedule

Monthly 25MW Blocks	8400	9200	7600	8800	8400	8000	8800	8800	8000	8800	9200	8400
Number of Installments	6	6	6	6	6	6	6	6	6	6	6	6
Purchase Dates	**Sep-08**	**Oct-08**	**Nov-08**	**Dec-08**	**Jan-09**	**Feb-09**	**Mar-09**	**Apr-09**	**May-09**	**Jun-09**	**Jul-09**	**Aug-09**
2/1/08	-	-	-	-	-	-	-	-	-	-	-	-
3/1/08	16,800	9,200	15,200	17,600	16,800	24,000	-	-	-	-	-	-
4/1/08	8,400	18,400	15,200	17,600	25,200	16,000	17,600	-	-	-	-	-
5/1/08	16,800	9,200	7,600	8,800	16,800	24,000	17,600	17,600	-	-	-	-
6/1/08	8,400	18,400	15,200	17,600	16,800	16,000	17,600	8,800	16,000	-	-	-
7/1/08	16,800	9,200	15,200	17,600	25,200	24,000	17,600	17,600	8,000	17,600	-	-
8/1/08	8,400	18,400	15,200	17,600	16,800	16,000	8,800	8,800	16,000	17,600	18,400	-
9/1/08	-	-	-	-	-	-	17,600	17,600	16,000	17,600	27,600	25,200
10/1/08	-	-	-	-	-	-	-	8,800	16,000	17,600	18,400	25,200
11/1/08	-	-	-	-	-	-	-	-	8,000	26,400	27,600	25,200
12/1/08	-	-	-	-	-	-	-	-	-	17,600	18,400	33,600
1/1/09	-	-	-	-	-	-	-	-	-	-	27,600	25,200
2/1/09	-	-	-	-	-	-	-	-	-	-	-	25,200
Total	75,600	82,800	83,600	96,800	117,600	120,000	96,800	79,200	80,000	114,400	138,000	159,600
tal Open including Rounding	644	(2,877)	(583)	(11)	(1,449)	1,977	2,455	3,285	2,394	(2,822)	(4,377)	(609)
Peak Residential Volume	76,244	79,923	83,017	96,789	116,151	121,977	99,255	82,485	82,394	111,578	133,623	158,991

The resulting ranges of costs look again like S shaped curves, but they are narrower than under the all-spot strategy:

Figure 9: Comparative Risks of Multi-Installment Procurement Strategies: 100% 6x12 Flat Block vs. 100% 6x6 Block-Diagonal

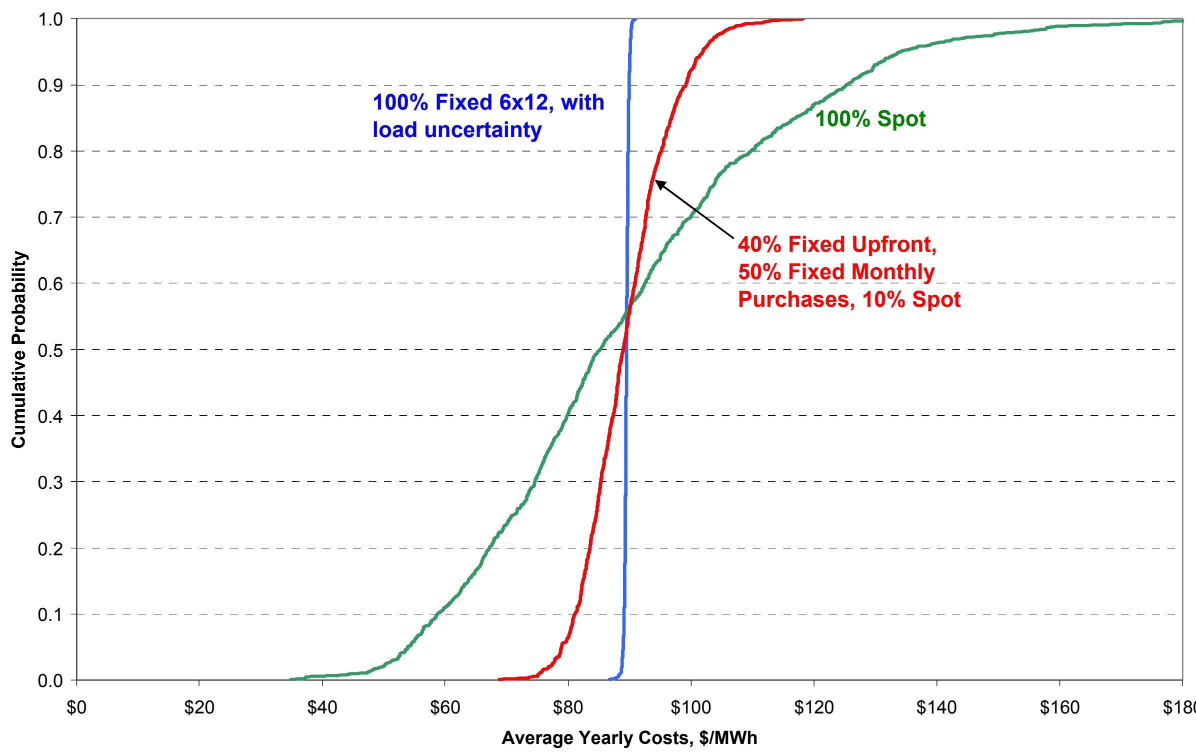


Note: 6x12 flat block purchases are done in 6 installemnts starting in March 2008 for September 2008 through August 2009 delivery.
6x6 block-diagonal purchases are done in 6 installemnts starting in March 2008 for September 2008 through February 2009 delivery. April 2008 purchases are done for September 2008 through March 2009 delivery, etc.

Where the all-spot curve ranged from about $40 to $160/MWh, both of these cumulative probability distributions are in the $60-120 range, and the 6 X 12 schedule is tighter than the 6 X 6 schedule. One useful measure of the cost uncertainty is the range of potential price per MWh spanned from the 10th percentile low price to the 90th percentile high price, drawn above as bars of length $33 or $26/MWh for the 6 X 6 vs. 6 X 12 schedules, respectively. The 6 X 6 schedule is wider (riskier) because it leaves more of the future needs uncovered until closer to the delivery date. Thus, it is more exposed to changes in the forward prices of power in the time from today to when those purchases are made. Note that both strategies' cost distributions cross the 50th percentile at the same price, around $90/MWh, which is also where the all-February, nearly vertical curve lay and where the all-spot curve crossed the 50% level. This demonstrates an important point: But for transactions' costs, risk management does not reduce or alter the expected cost, just the range of potential costs.

A more sophisticated portfolio might blend some annual contracts, some of the above installment purchases, and some spot into a composite portfolio. This possibility is shown in Figure 10 below, using a blend of 40% annual baseload contracts purchased all in February, 50% of total energy needs purchased under the 6 X 12 schedule, and the remaining 10% at day-ahead spot prices.

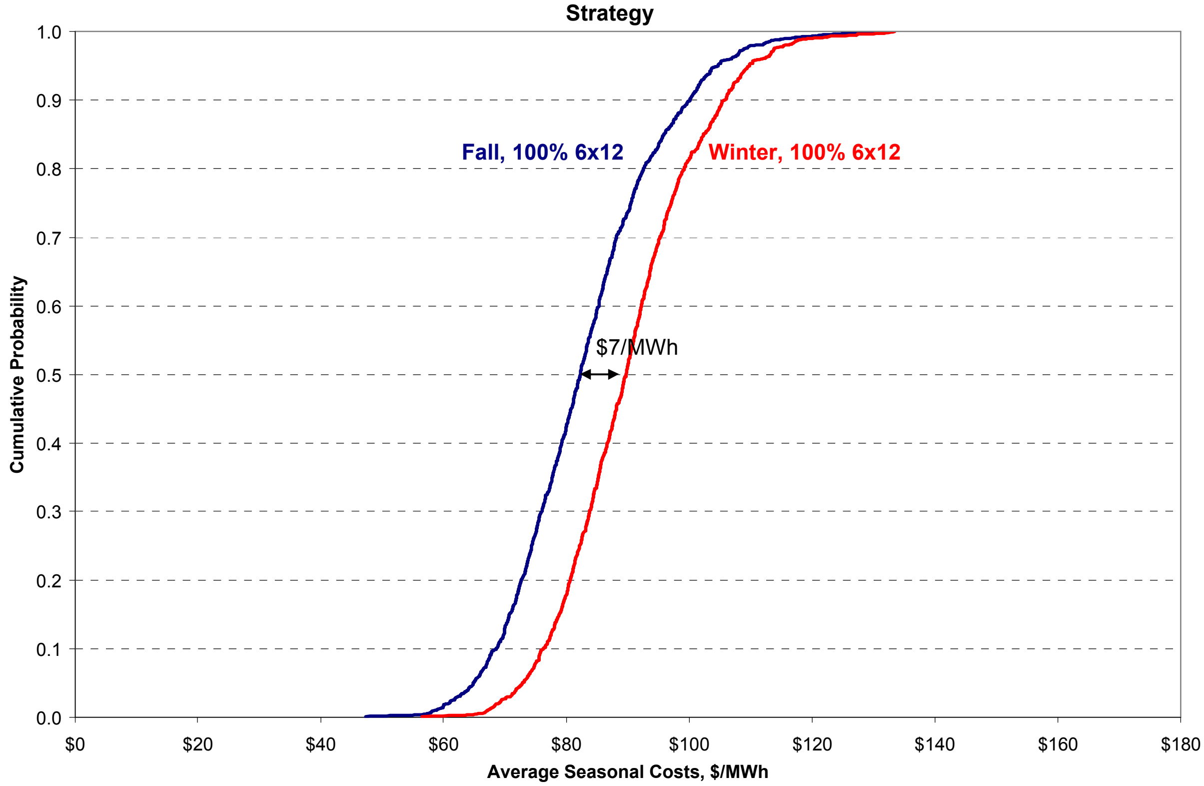
Figure 10: Composite Portfolio Risk vs. All Fixed or All Spot Strategy



Also shown in Figure 10 are the all-spot and all-February 2008 strategies from Figure 6. The composite strategy has annual costs that lie largely between $80 and $100/MWh, a much tighter range than all spot.

The above figure describes average annual costs per MWh. It is important to keep in mind that each season has a different expected cost and volatility, and so each will have its own range of possible cost outcomes under a portfolio. Those seasonal differences can be either passed on to customers via seasonal tariffs, or internalized by the utility under an annual fixed-price tariff. However, the latter will only be possible if (1) the utility has the financial health to bear the mid-period variations between revenues and costs that would result and (2) there is a reliable method for eventually recovering those net differences in a balancing account that is amortized over future periods. The extent of currently prevailing differences in seasonal characteristics for fall and winter is shown below:

Figure 11: Seasonal Differences in Costs and Risks of Multi-Installment Procurement Strategy



This graph shows that on-peak electric energy prices for deliveries in Delmarva's zone next fall (September through November 2008) are currently expected to cost about $80/MWh while the winter is expected to be about $7/MWh higher. The fall distribution is also a bit wider (hence riskier) than the winter. If summer of 2009 had been shown, it would have been a bit more than $3/MWh higher in average cost and much wider in potential range of outcomes.

There are at least three reasons why seasonal pricing may be attractive compared to annual pricing. First, it provides a more efficient price signal to SOS customers, so they can make better consumption and investment decisions. Second, seasonal prices will stay in closer harmony with prevailing wholesale prices, reducing the temptation of customers to switch suppliers simply because they are not seeing the true, contemporaneous cost of their SOS service. Third, shorter-term pricing reduces the working capital costs incurred by the utility.

Figure 12 on the next page provides a summary comparison of several portfolio alternatives, in terms of their average cost per MWh and their range between the 10th and 90th percentiles. Each strategy is presented first on a seasonal basis, in the first four sets of rows, and then on an annual basis in the bottom set of rows. Reiterating a point made earlier, it is important to notice that the average cost does not vary by risk management strategy. [28] In contrast, what does vary significantly is the range of possible outcomes, which can be almost as great as the average cost itself when all supplies are taken at spot. Of course, an all-spot supply is not recommended, but it does reveal how significant the risk is in wholesale electricity markets.

This might lead one to wonder whether it isn't best to simply buy as much forward as soon as possible. By using more forward purchases, the a priori risk does decline, but this increases the risk of after-the-fact regret -- which experience has shown is almost equally important to regulators and customers. Having a narrowly fixed price for SOS service also increases the risk of customer migration. This occurs only at a loss to the SOS service provider, since the customer will shift suppliers under circumstances favorable to him or her. That is, customers will leave SOS for a third-party retail provider when the SOS price is higher than the market, causing the SOS supplier to have to dump some supplies at a loss. Alternatively, customers will return to SOS when it is cheaper than the services retail providers are offering, when the SOS provider will have to procure supplemental power at a higher cost than it is being allowed to charge for the service. Those losses have to be made up by other, non-migrating customers or else Delmarva's credibility as a buyer could decline, perhaps dramatically enough to compromise the whole process. Even if market prices do not fall to induce this result, it is possible that competitive suppliers may make certain

[28] Ignoring transaction costs there is some slight variation, which arises because only 1000 random simulations were performed for each portfolio alternative, which come out slightly differently each time they are run.

creative service offerings (e.g., "green" power) that lead to significant unanticipated customer switching.

Another reason for limiting the amount of forward coverage is that such contracts are fixed-cost liabilities for Delmarva. As a result, they may be deemed to be debt-equivalent transactions that impair the utility's debt rating and raise its cost of capital.

Figure 12: Total and Average Expected Costs of Peak Electricity Procurement for Delmarva

Electricity Hedging Option	Total Expected Electricity Volume (MWh) [1]	Total Expected Costs (MM) [2]	Total Average Costs ($/MWh) [3]=[2]/[1]	Difference between High and Low Average Costs ($/MWh) [4]
Settlement Period: 09/08 to 11/08 (On-peak)				
1 Fixed, 0 Open, 1 installment	239,184	$19.84	$82.97	$2.25
1 Fixed, 0 Open 6x12	239,184	$19.89	$83.16	$31.54
0.4 Fixed Upfront, 0.5 Fixed, 0.1 Open	239,184	$20.51	$85.75	$17.29
0 Fixed, 1 Open	239,184	$19.85	$83.01	$58.48
1 Fixed, 0 Open 6x6	239,184	$19.89	$83.16	$31.54
1 Fixed, 0 Open 3x3	239,184	$19.89	$83.16	$24.05
1 Fixed, 0 Open, different volatility	239,184	$19.88	$83.11	$25.68
Settlement Period: 12/08 - 02/09 (On-peak)				
1 Fixed, 0 Open, 1 installment	334,917	$30.21	$90.19	$1.01
1 Fixed, 0 Open 6x12	334,917	$30.24	$90.29	$29.39
0.4 Fixed Upfront, 0.5 Fixed, 0.1 Open	334,917	$30.11	$89.90	$20.52
0 Fixed, 1 Open	334,917	$30.21	$90.21	$70.55
1 Fixed, 0 Open 6x6	334,917	$30.24	$90.29	$29.39
1 Fixed, 0 Open 3x3	334,917	$30.25	$90.32	$22.29
1 Fixed, 0 Open, different volatility	334,917	$30.23	$90.25	$22.38
Settlement Period: 03/09 - 05/09 (On-peak)				
1 Fixed, 0 Open, 1 installment	264,134	$23.41	$88.62	$2.25
1 Fixed, 0 Open 6x12	264,134	$23.38	$88.53	$22.96
0.4 Fixed Upfront, 0.5 Fixed, 0.1 Open	264,134	$23.42	$88.67	$13.78
0 Fixed, 1 Open	264,134	$23.41	$88.63	$65.77
1 Fixed, 0 Open 6x6	264,134	$23.34	$88.36	$30.47
1 Fixed, 0 Open 3x3	264,134	$23.38	$88.53	$25.75
1 Fixed, 0 Open, different volatility	264,134	$23.39	$88.57	$16.24
Settlement Period: 06/09 - 08/09 (On-peak)				
1 Fixed, 0 Open, 1 installment	404,192	$37.77	$93.45	$1.73
1 Fixed, 0 Open 6x12	404,192	$37.78	$93.48	$23.65
0.4 Fixed Upfront, 0.5 Fixed, 0.1 Open	404,192	$37.22	$92.08	$18.86
0 Fixed, 1 Open	404,192	$37.75	$93.41	$78.30
1 Fixed, 0 Open 6x6	404,192	$37.70	$93.29	$44.72
1 Fixed, 0 Open 3x3	404,192	$37.72	$93.32	$39.70
1 Fixed, 0 Open, different volatility	404,192	$37.78	$93.46	$16.02
Settlement Period: 09/08 - 08/09 (On-peak)				
1 Fixed, 0 Open, 1 installment	1,242,427	$111.23	$89.53	$0.81
1 Fixed, 0 Open 6x12	1,242,427	$111.29	$89.58	$26.45
0.4 Fixed Upfront, 0.5 Fixed, 0.1 Open	1,242,427	$111.26	$89.55	$18.05
0 Fixed, 1 Open	1,242,427	$111.23	$89.53	$66.44
1 Fixed, 0 Open 6x6	1,242,427	$111.17	$89.48	$32.78
1 Fixed, 0 Open 3x3	1,242,427	$111.24	$89.54	$26.21
1 Fixed, 0 Open, different volatility	1,242,427	$111.27	$89.56	$19.61

d. The Role of Physical Assets in SOS Supply

Incorporating a gas peaking unit into the supply portfolio might alter the costs and risks. To do this in a fashion fully compatible with the above risk analysis, it would be necessary to use a model that analyzes transactions at the hourly level. This is because a peaking unit will not be used at a steady level in some months but not others, or even for all of the 16 on-peak hours in a day, even in the summer. Instead, it will be used in those few hours per day when its operating costs (gas costs * heat rate + variable O&M) are below the hourly spot price of power. The model underlying this report is not an hourly model, so directly including a peaker in the simulated supply mix is not feasible. Instead, in order to assess how useful a peaker might be, its operations were evaluated retrospectively, as if a unit had been available to dispatch against the hourly spot prices in Delmarva's zone in calendar years 2006 and 2007. The results are shown in the following table.

Figure 13: Retrospective Benefits of Gas Peaker

Date	Average Price (MWh)		Return Volatility		Economic %				
	Peak DLP LMP Day Ahead [1]	Peak DLP LMP Day Ahead w/Peaker [2]	DPL LMP Day-Ahead [3]	DPL LMP Day-Ahead w/Peaker [4]	DPL Spot Market [5]	Peaker (w/O&M costs*) [6]	Average Cost per MWh avoided by Gas Peaker [7]	Total Saving [8]	PJM Capacity Market (Monthly) [9]
1/2006	66.91	66.40	9.90	9.77	94.7%	5.31%	9.38	159.53	4,219
2/2006	64.49	63.89	8.28	7.93	93.8%	6.25%	9.61	182.62	261
3/2006	61.94	61.74	6.12	5.85	97.0%	2.99%	5.95	65.48	66
4/2006	60.22	60.19	7.45	7.41	99.3%	0.66%	5.30	10.59	46
5/2006	54.40	54.04	5.55	5.55	96.7%	3.27%	10.85	119.40	38
6/2006	65.46	61.53	8.18	6.49	74.1%	25.85%	15.13	1,377.19	88
7/2006	92.42	72.42	14.15	6.63	40.1%	59.87%	33.33	6,066.52	2,212
8/2006	100.56	76.22	14.51	6.42	57.1%	42.93%	56.65	8,951.29	200
9/2006	47.92	46.80	8.08	7.10	88.1%	11.88%	9.27	352.32	308
10/2006	53.38	53.00	7.81	7.73	94.6%	5.36%	6.30	113.35	42
11/2006	61.65	61.41	8.80	8.74	96.3%	3.75%	6.21	74.55	28
12/2006	55.29	54.60	9.70	9.43	91.8%	8.22%	8.18	204.56	42
2006 Average	65.38	61.02	9.04	7.42	85.3%	14.7%	14.68	17,677	-
2006 Sum	-	-	-	-	-	-	-	17,677	7,548
Total Value of Peaker									25,226
1/2007	56.52	56.17	11.77	11.11	96.7%	3.27%	10.13	111.39	68
2/2007	79.03	78.81	13.98	13.88	96.7%	3.29%	6.48	64.81	44
3/2007	71.60	70.22	12.43	12.00	88.6%	11.36%	12.05	482.01	37
4/2007	73.25	73.10	6.69	6.62	97.2%	2.81%	4.93	44.35	85
5/2007	71.32	70.30	7.63	7.27	92.0%	7.95%	12.56	351.60	52
6/2007	84.04	75.54	11.93	7.74	67.5%	32.50%	26.06	2,710.17	5,997
7/2007	82.30	68.39	12.01	5.67	47.0%	52.98%	26.19	4,661.01	5,997
8/2007	93.75	71.24	11.21	5.13	32.9%	67.12%	33.49	8,271.26	5,997
9/2007	71.02	63.29	8.87	5.51	59.2%	40.79%	18.90	2,343.49	5,997
10/2007	77.96	70.91	11.16	8.26	64.2%	35.80%	19.53	2,460.95	5,997
11/2007	72.71	70.87	9.04	8.51	84.4%	15.63%	11.57	578.29	5,997
12/2007	81.80	81.52	11.95	11.81	97.4%	2.57%	10.48	73.35	5,997
2007 Average	76.28	70.86	10.72	8.63	77.0%	23.0%	16.03	22,153	-
2007 Sum	-	-	-	-	-	-	-	22,152.66	42,263
Total Value of Peaker									64,416

*O&M costs = $2/MWh.

The rows in Figure 13 correspond to months. The columns compare the average spot price (modeled on an hourly basis, but summarized here for the whole month) of energy with and without using a peaker in any hour when it would have been cheaper than spot. In 2006, a peaker would have been used in about 15% of the hours and would have lowered the average energy price by about $4/MWh, vs. 23% of the hours in 2007 for about a $5.50/MWh average savings. Because the peaking unit clips off some of the highest price hours, its use would also reduce the volatility of the spot energy, as seen in columns 3 and 4 above. The total dollar value of those energy savings per MW-year is shown in the next to last column: $17,677 in 2006 and $22,153 in 2007. Assuming a combustion turbine requires about $72,000 per MW-year to cover all of its fixed costs, these results would not have justified owning a peaking unit at that time.

There would also have been PJM capacity credits, the past values for which are shown in the last column. Capacity prices were trivial in 2006 but more substantial in 2007, especially after the RPM prices took effect in June -- though they were still not enough to bring the units up to full cost recovery. However, looking forward, the RPM capacity prices might be become high enough that a peaking unit could be economic

e. Process for SOS Procurement Specification

The foregoing is not intended to be sufficient for specifying the goals or choosing a portfolio management approach for Delmarva's SOS coverage. It involves many simplifications that would be important to transcend with more thorough modeling and analysis. First, all of the above results have been analyzed and shown just for the on-peak hours. Off-peak hours will have an average cost that is often $20/MWh or more below the on-peak average in a given day or month, and they will have less risk. So the above graphs do not depict the full story of what the average energy and congestion costs are likely to be for Delmarva – they are purely illustrative of how alternative procurement strategies would affect risk.

The above analysis also involves no intra-day load shaping and load uncertainty, nor any customer switching analysis. Since load uncertainty and spot price uncertainty tend to be highly correlated, this simplification means the risks are understated and some strategies not yet evaluated may be more attractive than any of the portfolio strategies described above. This analysis also understates costs by not including several supply elements needed to convert wholesale power into retail service, including capacity prices, ancillary services, and losses.

This analysis also addresses only what the total energy supply risk may be per season or year, not how that risk will be allocated over time between Delmarva and its customers. No analysis has been conducted of how SOS might be priced and how the resulting revenues would compare to the costs incurred by Delmarva. There is some practical, financial limit on how far apart a utility's costs and revenues can get, and that may constrain what portfolio designs are feasible. In particular, it may affect how far ahead of delivery Delmarva may be able to purchase fixed price obligations.

Other supply composition mixes or technologies may also be of interest. For instance, it may be useful to consider more baseload supply, or earlier or later installment purchases. Physical assets such as a gas peaking unit or renewable resources could be simulated, though they can only be understood in a more elaborate model. Call options could be considered as a means of mitigating some of the risk of spot prices rising, while leaving open the possibility of prices declining.

The missing elements require quantitative modeling so that realistic insights can be gained. A process of iterative, collaborative discussions of the costs and risks of alternative designs, informed by additional and more robust modeling, could be an efficient vehicle to help Delmarva, Staff, and the DPA reach agreement on the “rules of the road” for guiding the implementation of a managed portfolio strategy. That agreement should also include a specification of procurement processes, risk targets, performance monitoring and controls, reporting practices, conditions for altering the procurement goals or procedures, pricing policies, cost recovery/prudence criteria, and customer switching policy revisions, if necessary.

6. Portfolio Management Implementation Issues:

The sections above described many of the resource options that could be included in an actively manage resource portfolio including long term commitments and regulated generation assets and how some example portfolios might be expected to perform. Delmarva is prepared to take responsibility for managing a resource portfolio and begin the process of transitioning from the current SOS procurement practice to an actively managed resource portfolio as authorized by the Commission. However, before Delmarva can actually recommend a specific combination of resources to include in the portfolio, there are a number of significant operational issues related to implementing portfolio management that Delmarva respectfully submits should be resolved prior to Delmarva actually acquiring portfolio resources. At some point prior to the start of Delmarva actively managing the resource portfolio, the Commission will need to approve rules and regulations governing these issues. Once the "rules of the road" are established, Delmarva can put forward for Commission review, as appropriate, specific proposals for acquiring and managing portfolio resources

While it will likely be Delmarva's responsibility to manage the SOS resource procurement portfolio, Delmarva also believes that the transition to portfolio management will be greatly benefited by resolving these issues up front through a collaborative working process that will develop proposed rules and operating procedures under which Delmarva would operate the resource portfolio. Delmarva will be responsible for submitting rules under separate application to the Commission for review and approval prior to actual implementation of the portfolio. Specifically, Delmarva recommends that the Commission authorize the establishment of a Portfolio Working Group composed of Delmarva, Staff, and the Delaware Public Advocate. The purpose of the Portfolio Working Group will be to evaluate proposed rules and regulations governing the implementation and on-going operation by Delmarva of an SOS customer supply resource portfolio.

After authorization of the Portfolio Working Group, Delmarva estimates that it will take approximately four months to prepare a set of findings and recommendations for Commission review. As the portfolio manager, Delmarva will take the responsibility of scheduling the meetings of the working group to assure that the work is completed on schedule. Delmarva will have the responsibility to file, under separate application, the recommendations of the Portfolio Working Group for Commission review and approval. If a decision can be reached by October 15, 2008, Delmarva can then curtail the Full Requirements SOS contract procurement process for June 1, 2009 delivery and begin acquiring portfolio resources to manage SOS procurement for implementation on June 1, 2009. If a decision is not reached by October 15, 2008, Delmarva respectfully submits that due to the 8-9 month lead time associated with obtaining new FRS contracts, the next window of opportunity for portfolio implementation will not become available until June 1, 2010.

The Company notes that the proposed collaborative Portfolio Working Group is very similar to the process used by this Commission in establishing the rules and procedures for implementing the SOS procurement improvements in Docket No. 04-391, see Order No. 6943. The Company notes that the process used to develop the rules and guidelines for the SOS process worked very effectively and would encourage the Commission to follow a similar approach here.

Some of the key issues to be resolved prior to implementation of the actively managed portfolio include: a) Non bypassable distribution charges and restriction of customer choice; b) Power Supply Cost and Revenue Imbalance; c) Portfolio Structure and Objectives; d) Portfolio Risk Management practices; and, e) Portfolio Implementation Schedule. Delmarva recommends that the proposed working group evaluate specific suggestions on each of these topics.

a. Non-bypassable Distribution Charges and Restriction of Choice

With retail choice, if Delmarva is required to manage a portfolio, and that portfolio includes longer term resources (for example, 5 – 10 year contracts, utility-owned generation assets), then Delmarva runs a significant risk associated with customers migrating to alternative suppliers. Once those customers have migrated, Delmarva's remaining customers must pay for those stranded resources. One way to combat this problem would be to implement non-bypassable distribution charges for SOS eligible customers related to active portfolio management activities including long term commitments. This non-bypassable charge would assure that all SOS eligible customers are responsible for any stranded costs, no matter who their supplier is. Delmarva believes that, absent a non-bypassable charge or restrictions on choice, customer choice provides a disincentive for longer term resources to be included within a resource portfolio. In the future, it may be appropriate to consider restricting customer choice in lieu of imposing non-bypassable charges.

A review of the most recent switching statistics in Delaware indicates that as of January 25, 2008, only 8,843 Delmarva residential customers or 3.3 % of all residential customers had selected suppliers other than Delmarva29. In contrast, 4,916 non-residential customers representing about 15% of non-residential customers but almost 65% of the non-residential capacity obligation have their energy needs served by alternate suppliers. If Commission policy was to direct Delmarva to manage the SOS resource portfolio primarily for the benefit of residential and small commercial customers, it might only be necessary for non

[29] Delaware Electric Supply Choice Enrollment Information, Monthly Report for period ending January 25, 2008.

bypassable charges or restrictions of choice to be established for this group of customers.

b. Power Supply Cost and Power Revenue Imbalance

As stated above, Delmarva is prepared to perform the portfolio management function. A managed portfolio, without the risk of customer switching and with the option of longer term resources locking in prices over time, may better meet the goals of price stability, reasonable cost and meeting the RPS standards. However, unlike the current SOS procurement process, an actively managed portfolio will lead to situations where supply revenues may not equal supply costs over any given period of time which will require a true-up mechanism. The appropriate procedures and statue requirements to handle supply cost and revenue discrepancies should be evaluated by the Portfolio Working Group and submitted to the Commission for its consideration and approval.

There are several situations where supply costs and revenues may diverge. If the Company's rates for power procurement did not change coincident with any significant change in the cost basis for the power procurement, such as when a new supply resource came into service, then a supply cost and revenue imbalance would occur. In addition, shorter term swings in power purchase costs due to; a) spot market price changes, b) a new wholesale supply contract becoming effective or c) variations in customer usage, such as those that occur with severe weather, should be taken into account with a fuel adjustment type mechanism. This mechanism would adjust charges at least on a quarterly basis, if not monthly, in order to keep power procurement expenses and revenues in balance. Any monthly differences between power procurement costs and power procurement expenses should be accrued in deferred accounts as regulatory assets or liabilities. If necessary changes in the fuel adjustment mechanism are frequent, then it would not be necessary to accrue carrying costs on the monthly balances, as the balances would be relatively small. If the fuel adjustment mechanism is infrequent, then the balances in the deferred accounts could become significant and it would be appropriate to accrue carrying charges on the asset or liability.

Delmarva believes that reasonable regulation to accompany this change in industry structure will greatly facilitate the process. Delmarva has in the past been subject to regulatory reviews associated with managed coal and other fuel resources, and is willing to undertake management of a portfolio of supply resources under similar regulation. Such portfolio management could also include utility-constructed generation if that is determined to be a least-cost option going forward.

If the Commission determines that the optimal policy direction is to re-regulate supply service to residential and small commercial customers in order to bring reliability benefits and price stability, then Delmarva should manage the portfolio for their customers, much in the same way that it was managed under traditional regulation. Under traditional supply regulation, Delmarva was allowed to include generation investments in rate base, recover fuel costs through an approved fuel cost adjustment mechanism, and there was no customer choice.

If the Commission desires to re-institute regulated generation, Delmarva would expect the Commission to review procurement just as in the past with the operation of the fuel adjustment clause and currently done for the SOS procurement. If a review is to take place, the Commission should first establish guidelines and provide parameters for performance in advance. Also, the after the fact review must be based on what the Company knew at the time the procurement decisions are made; the Commission should judge the utility's actions and not disallow cost recovery unless there is a showing of waste, bad faith or abuse of discretion based on what the utility knew at the time the decision was made, rather than with the advantage of hindsight. Regulators might find it difficult not be influenced by hindsight, especially if they are subjected to undue pressure, to restrain price increases in a time of rising inflationary pressure. This concern is greatly increased when the decisions in question relate to transactions involving vast sums of money, or which (in the case of SOS procurement) the utility earns very modest returns even in the absence of any disallowance.

Further, the rebuttable presumption of cost recovery is essential to the impact of a new procurement process on the financial position of regulated utilities. If the expectation is that a company will be permitted to recover its costs, absent a deviation from the law, Delmarva does not have a significant concern with respect to the financial impact of such a change. If, however, there is not a rebuttable presumption of cost recovery and no guidelines are established in advance, the risk that would be perceived by the investing and investment rating community could have a significant impact on the company's financial position and ultimately customer costs.

The Delaware Commission has a long history of carefully applying the appropriate standards in its review of cost recovery dockets related to regulated generation. If the Commission determines that a re-institution of regulated generation should occur, Delmarva is confident that the transition back to this more traditional form of regulation will be a successful one.

c. Portfolio Structure and Objectives

There is no single, predictable way to determine what the optimum portfolio should be. Indeed, the concept of optimization itself is dependent upon the goals to be achieved, the risk tolerance to be embraced, the products that are deemed appropriate, and the specific rules and guidelines controlling portfolio management. At any given time the portfolio may not be considered optimum, although in the long run it may perform as desired. The best practice for active management will include frequent evaluation of performance given load and price forecasts, and periodic adjustments through purchases and sales that will bring expected performance within the range of year-to-year retail rate changes that have been established. Once the basic guidelines have been established, Delmarva would expect to develop the appropriate forecasts and evaluate the available market products with which to begin establishing the portfolio.

If the purpose of the actively managed portfolio is to reduce year-to-year volatility, the implication is that some price concessions will be made to fix future prices. The simple example is a call option on energy. The option puts a cap on the price to be paid in the future. However, there is a cost to buy the option. For the very long term, the option might be created by current investment in a generation asset. This will create a known future fixed cost, but will tie customers to a specific fuel and require customers to accept operational, environmental, and other related risks. Each of these risks may in turn be mitigated, but always at a cost.

The procurement strategy under any of the portfolio management options discussed above would be a blend of both resources and timeframes. For example, one of the advantages of a regulated portfolio would be that supply would use a combination of short, medium and long term contracts to provide price stability. Similarly, for any owned resources, there may be a mix of fuel supply contracts. Renewable resources used to meet the Delaware RPS could also rely on a blend of contract lengths and terms.

There is risk associated with any approach that will be taken, and one or more parties are compensated for that risk. Under the current SOS procurement structure, suppliers take on most of the risk (e.g., load following) and are compensated through the price that they charge. In a regulated portfolio approach, it would still be necessary to compensate the parties for the risks that they take, but the distribution of risk between suppliers and portfolio managers will be different. By restricting customer switching rights and moving towards longer-term, utility-managed portfolios of contracts and perhaps utility-owned generation, it would be possible to significantly change the mix of costs and risks of SOS service.

d. Portfolio Risk Management

Since the portfolio approach would also allow Delmarva to more actively manage the risks associated with SOS supply procurement, Delmarva would expect to prepare appropriate risk management policies and controls. The risk management policy, which would be an integral part of the procurement plan, would define the parameters under which the overall risk of the portfolio would be managed. Such parameters might include: keeping the year-to-year price increases to no more than a certain %, limiting single actions to have no greater effect on the next price change of more than a certain amount, requiring the market exposure to remain within a specified limit (based on volume and price changes), and establishing the amount of supply that is unhedged in future periods. Delmarva proposes that these issued be discussed by the Portfolio Working Group and that Delmarva will bring the appropriate recommendations to the Commission for review and approval.

Where large positions are being considered for a portfolio, such as acquisition of a generating resource, prior review by the Commission would be expected. Likewise, the Commission might direct in advance that a certain amount of renewable resources should be acquired for a long term period, consistent with Renewable Portfolio Standards requirements. Finally, if the Commission orders the Company to enter into long term contracts, the contracts must be carefully structured to avoid having the contracts viewed as debt on the Company's accounting books by the rating agencies.

In traditional supply regulation, the utilities would develop a long-term portfolio procurement plan that would be reviewed by the Commission. The utility would implement the Commission-reviewed procurement plan. In today's environment and as discussed above, such a plan could consider a mix of resources that would include renewable portfolio standards, and a potential mix of contracts, demand-side resources, owned generation and spot market purchases. For example, consider an actively traded portfolio where there is significant latitude given to the manager to interact with the power market and own rights to generation assets, fuel supplies, etc. Risks in this example would include price risk, supply risk, credit risk, operational risk, environmental risk, fuel supply risk and regulatory risk. If customers are required to pay the cost of the portfolio, then customers will bear certain of these risks in part; the customers also should see lower prices since the suppliers are no longer bearing all of the risks. The utility also will bear some risk associated with its management of the portfolio. The utility would require compensation for that risk as well. Therefore, a fundamental design criterion for such a portfolio is the extent of the risk that will be acceptable for customers. The design of the portfolio must address the measurement of the risks, and establish control procedures to limit the risks.

e. Portfolio Implementation Schedule

Building a diversified supply portfolio will take time. Delmarva believes that procuring all supply resources over a short period would be little different than conducting an SOS RFP for 100% of the load at one time. It would be best to develop an implementation plan to establish a future date by which a forward portfolio is to be in place. As discussed above, the implementation schedule must recognize the termination dates of existing FRS contracts as well as the annual

RPS requirements. Given these constraints, Delmarva sees the earliest implementation to be phased in over several years possibly beginning as early June 1, 2009 as approximately one third of the full requirements service SOS RSCI contracts expire. The specific schedule for the phased implementation of the actively managed portfolio is a topic for discussion by the Portfolio Working Group and will depend in part on the timeliness with which the Portfolio Working Group can develop the proposed rules and guidelines and the Commission review and approval process.

7. Resource Portfolio Suggested Path Forward:

Delmarva is prepared to accept the responsibility and challenge of actively managing a resource portfolio for procuring SOS customer energy requirements. The portfolio could be composed of a variety of resources of different types, terms and attributes including longer term resources, green resources and regulated assets. Prior to submitting a specific portfolio for Commission approval, Delmarva strongly recommends that the rules and guidelines governing the management and operation of the portfolio be formalized. This will allow the "rules of the road" to be established prior to the portfolio being implemented.

As of the current date, the first window of opportunity for Delmarva to possibly begin managing a resource portfolio for SOS energy procurement will be on June 1, 2009 when approximately one third of the already in-place RSCI full requirements service SOS contracts expire. If this date cannot be met, the next "window" would not open until June 1, 2010.

Consistent with this objective, Delmarva recommends the following:

1. Upon acknowledgement of this updated IRP, the Commission authorize the creation of a collaborative Portfolio Working Group composed of representatives of Delmarva, Staff, and the DPA.
2. The Portfolio Working Group establish proposed rules and guidelines for operating managing the portfolio including, but not limited to, the following topics:
    a. Obtaining resources through contracts of various terms for fixed quantities of energy and capacity;
    b. Establishing hedge positions with fuel contracts associated with specific generators;
    c. Limits for the amount of spot and short term purchases to be used to balance the differences between customer load and portfolio resources;
    d. Rules and regulations governing the daily conduct and operation of the active management of the supply resource portfolio;
    e. Contracts for unit specific generation, and/or new utility owned generation to be included in rate base to meet reliability or electricity price hedging objectives.
    f. Monitoring and reporting requirements
    g. Risk mitigation practices
3. The Portfolio Working Group will make specific recommendations regarding cost recovery, the implementation of non-bypassable distribution charges, possible restrictions of customer choice and the operation and frequency of true-up mechanisms related to portfolio operation.

4. After authorization of the Portfolio Working Group, Delmarva estimates that it will take approximately four months to prepare a set of findings and recommendations for Commission review. As the portfolio manager, Delmarva will take the responsibility of scheduling the meetings of the working group to assure that the work is completed on schedule. Delmarva will have the responsibility to file under separate application, the recommendations of the Portfolio Working Group for Commission review and approval. If a decision can be reached by October 15, 2008, Delmarva can curtail the Full Requirements SOS contract procurement process for June 1, 2009 delivery and begin acquiring resources to manage a portfolio for implementation June 1, 2009.
5. As approved by the Commission, Delmarva will transition the existing SOS customer energy procurement process to a more actively managed resource portfolio. The portfolio will be managed by the objectives of achieving price stability and reasonable cost and meeting the Renewable Portfolio Standards.

VI. Reliability and Generation

1. Long Term Transmission Planning:

Delmarva Power's transmission facilities are located within the PJM Regional Transmission Organization ("RTO"). Delmarva Power works with PJM to ensure that reliability standards are met and that the necessary transmission facilities are built to meet the short term and long term needs of the Delmarva Peninsula.

PJM, as the RTO, is responsible for ensuring:

- Adequate generation or demand side resources across the entire region,; and
- Adequate transmission capacity to reliably and efficiently deliver the generation capacity where it is needed.

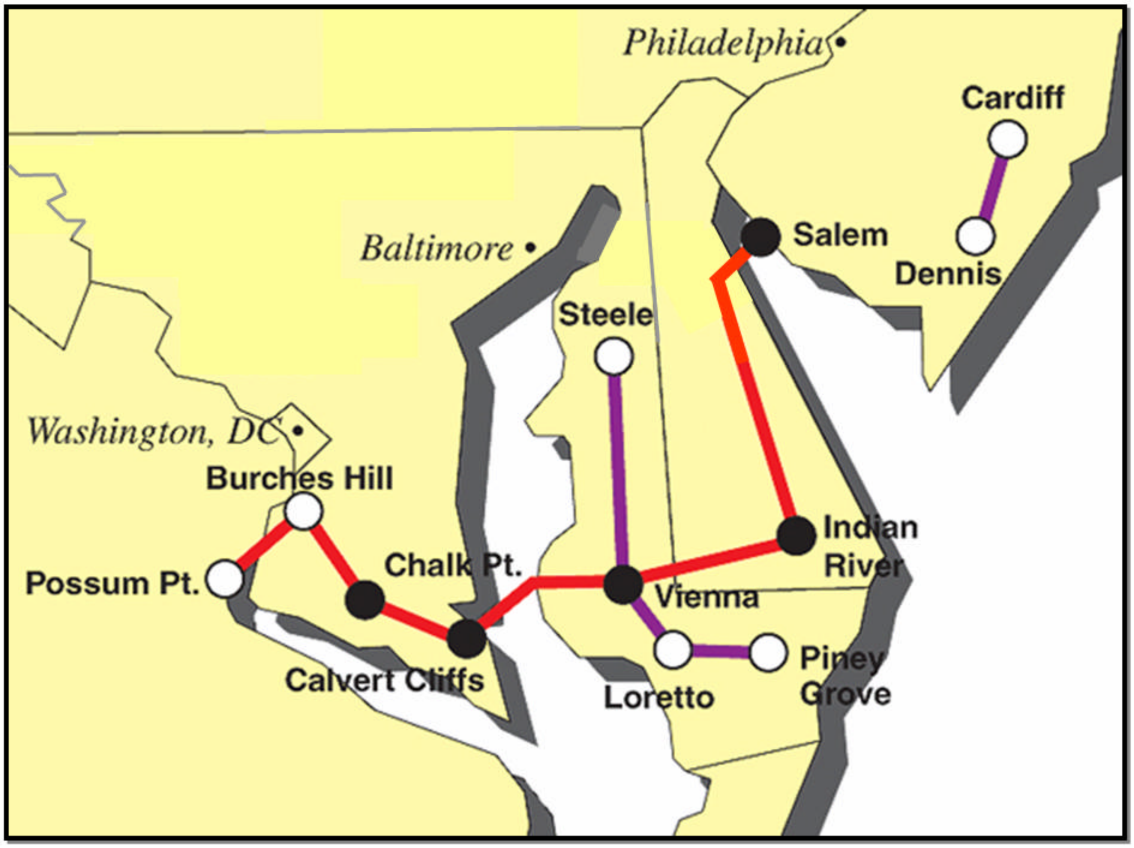
PJM meets these objectives by administering competitive markets that encourage merchant generation, transmission and demand-side resources. In addition, PJM as the regional planner identifies necessary transmission enhancements, in conjunction with Delmarva Power's planners, which are then included in the PJM Regional Transmission Expansion Planning ("RTEP") process.

PJM's planning process is a rigorous process that is outlined in PJM Manual 14-B, available on the PJM web site. The planning process takes into account the requirement that the future transmission system meet all applicable reliability criteria including: North American Electricity Reliability Council ("NERC"), Reliability First Corporation, PJM and Delmarva local planning criteria. PJM tests the system under both expected normal peak conditions and extreme conditions where peak loads are higher than forecasted and there are more generating units out of service than would be expected under normal peak conditions. Based on this analysis, PJM with support from Delmarva, develops a detailed 5 year plan to ensure that the transmission system has sufficient capability to serve the load. The transmission system plans that are developed include upgrades and additions to the transmission system as well as new reactive sources to assure that adequate transmission system voltages are maintained under all tested conditions. The table below provides a detailed listing of the individual transmission system upgrades that comprise the 5 year plan for Delmarva. A short description of each project as well as the PJM project ID#, expected in-service date and projected project cost are provided in the table. The information listed in the table is also available on the PJM web site.

Upgrade ID	Description	In-Service Date	Cost Estimate ($M)
b0241.2	Edge Moor Sub - Replace overstressed breakers	12/31/2008	$0.294
b0241.3	Red Lion Sub - 500/230kV work	5/31/2009	$12.630
b0241.4	Replace Keeney 230 kV breaker 231	5/31/2008	$0.254
b0241.5	Replace Keeney 230 kV breaker 233	5/31/2008	$0.254
b0261	Replace 1200 Amp disconnect switch on the Red Lion - Reybold 138kV circuit	5/31/2009	$0.053
b0262	Reconductor 0.5 mi of Christiana / Edgemoor 138kV line	5/31/2009	$0.175
b0263	Replace 1200 Amp wavetrap at Indian River on the Indian River - Frankford 138kV line	5/31/2010	$0.160
b0272.1	Replace line trap and disconnect switch at Keeney 500kV Sub - 5025 Line Terminal Upgrade	5/31/2010	$0.365
b0282	Install 46MVAR capacitors on the DPL distribution system	5/31/2009	$1.200
b0291	Replace 1600A disconnect switch at Harmony 230 kV and for the Harmony -Edgemoor 230kV circuit, increase the operating temperature of the conductor	5/31/2009	$1.635
b0295	Raise conductor temperature of North Seaford - Pine Street - Dupont Seaford 69kV	5/31/2009	$0.502
b0296	Rehoboth/Cedar Neck Tap (6733-2) upgrade	5/31/2008	$5.061
b0316	Upgrade Laurel - Mumford 69kV line operating temperature of 477 ACSR @ 125C to 140C	5/31/2009	$0.266
b0320	Create a new 230kV station that splits the 2nd Milford to Indian River 230kV line. Add a 230/69kV transformer and run a new 69kV line down to Harbeson 69kV	5/31/2010	$12.800
b0385	Oak Hall to New Church (13765) Upgrade	5/31/2008	$0.660
b0387	N. Seaford - Add a 2nd 138/69kV autotransformer	5/31/2008	$2.928
b0388	Hallwood/Parksley (6790-2) Upgrade	5/31/2009	$0.470
b0389	Indian River AT-1 and AT-2 138/69kV Replacements	5/31/2009	$6.999
b0414	Upgrade the Christiana - New Castle 138kV circuit	5/31/2009	$0.243
b0437	Keeney PRA 500/230kV Transformer	5/31/2008	$2.500
b0441	Keeney PRA 500/230kV Transformer (Monitoring Equip)	5/31/2008	$2.500
b0480	Rebuild Lank - Five Points 69 kV	5/31/2012	$1.440
b0481	Replace wave trap at Indian River 138kV on the Omar - Indian River 138kV circuit	5/31/2012	$0.135
b0482	Rebuild Millsboro - Zoar REA 69 kV	12/31/2008	$1.251
b0483	Replace Church 138/69 kV transformer and add two breakers	5/31/2009	$5.220
b0483.1	Build Oak Hall - Wattsville 138 kV line	5/31/2009	$2.685
b0483.2	Add 138/69 kV transformer at Wattsville	5/31/2009	$4.100
b0483.3	Establish 138 kV bus position at Oak Hall	5/31/2009	$1.200
b0484	Re-tension Worcester - Berlin 69 kV for 125 °C	5/31/2010	$0.158
b0485	Re-tension Taylor - North Seaford 69 kV for 125 °C	5/31/2010	$0.264
b0494.1	Install a 2nd Red Lion 230/138kV	5/31/2009	$3.418
b0494.2	Hares Corner - Relay Improvement	5/31/2009	$0.505
b0494.3	Reybold - Relay Improvement	5/31/2009	$0.230
b0494.4	New Castle - Relay Improvement	5/31/2009	$0.228
b0513	Maridel to Ocean Bay (6723-1) Rebuild	5/31/2012	$2.100
b0527	Bethany 69 kV - Add 30 MVAR of capacitors (Replace the existing 12 MVAR)	5/31/2010	$1.800
b0528	Bethany 138 kV - Add a 138/12kV transformer which will replace Bethany T1 69/12kV	5/31/2010	$4.900
b0529	Grasonville 69 kV - Add another 8.4 MVAR capacitor	5/31/2010	$1.300
b0530	Wye Mills 69 kV - Add 30 MVAR of capacitors (Replace the existing 12 MVAR)	5/31/2010	$1.800
b0531	Wye Mills 138 kV - Create a 4 breaker 138kV ring bus and add a 2nd Wye Mills 138/69kV transformer	5/31/2010	$6.000
b0xx	Mt. Pleasant to Townsend (13808-2) -Rebuild	5/31/2010	$4.208
b0xx	Trappe Tap to Todd (6716) -Rebuild	5/31/2010	$12.000
b0xx	Indian River - Add a 3rd 230/138kV Autotransformer	5/31/2011	$7.300
TOI111	2nd 69kV Stevensville line	12/31/2008	$3.382
TOI115	Valley Road 138/12kV Substation	5/31/2014	$2.221
TOI133	Dupont Seaford to Laurel (6736) Upgrade Phase 2	5/31/2011	$3.209
TOI137	Loretto AT-1 and AT-2 138/69kV Replacements	5/31/2011	$4.849
TOI142	Vienna to Sharptown (6705) Rebuild	5/31/2013	$1.280
TOI144	Church to Wye Mills - Establish a new 138kV Line	12/31/2014	$9.428
TOI147	Laurel to Short (6706) Rebuild	5/31/2013	$2.110
TOI148	Vienna to Nelson (13707) Rebuild	5/31/2014	$5.000
TOI158	Queenstown Sub - Establish 69/25 KV station	10/31/2012	$3.902
TOI159	Easton/Bozman -Convert 25KV to 69 KV	12/31/2009	$0.165
TOI164	Harmony-Add a 2nd 230/138 autotransformer	5/31/2012	$7.419
TOI240	Five Points/Lewes Tap (6751-3) - Rebuild	5/31/2012	$0.722
TOI242	Bridgeville/Greenwood (6738-1) - Upgrade	5/31/2008	$0.858
TOI244	Glasgow/Mt. Pleasant (13808-1) - Rebuild	5/31/2011	$5.700
TOI247	Church - Add a line position on the 138kV bus	12/31/2014	$0.715
TOI250	Cecil Sub - Add a 230/138kV autotransformer	12/31/2011	$5.431
TOI251	Delaney Sub - Removal	12/31/2008	$0.250
TOI352	Queenstown Sub - Transmission line for new sub	12/31/2012	$0.336
TOI354	Jacktown Sub - Install in-line switches	5/31/2010	$0.252
TOI355	Wye Mills / Easton (6707) - Convert to 138kV	5/31/2012	$1.299
TOI357	Darley / Silverside (6833) - Rebuild	12/31/2010	$1.296
TOI358	Easton - Create a 69kV bus position	12/31/2009	$1.239
TOI359	Bozman - Create a 69kV bus position	12/31/2009	$1.060

In addition to this 5 year detailed plan, PJM also develops a 15 year plan to determine the need for new major backbone transmission projects at 500 kV and above. This long term planning process has identified the need for a major 500 kV transmission upgrade which will serve the Delmarva Peninsula. This upgrade is the Mid-Atlantic Power Pathway ("MAPP"), shown in the diagram below. The 500kv portion of the MAPP project was approved by the PJM Board of Managers in October 2007. This project has a projected in-service date of 2013 and will provide additional reliability and economic benefits to the Delmarva Peninsula. Pepco Holdings, Inc. ("PHI") plans to implement this project in phases with certain of the segments targeted for 2011-2013 completion, which will result in benefits to the Delmarva Peninsula customers.

PHI/Delmarva has made significant progress towards meeting the projected in service date for the MAPP project. PHI/Delmarva has named the overall project manager and the remainder of the core team for this project to execute the siting, permitting and construction phases of the project. Initial design, siting, environmental and community outreach activities have begun. PHI expects to file a Certificate of Public Convenience and Necessity ("CPCN") application for the Maryland portion of the line by first quarter of 2009. PHI is working with PJM to evaluate various technology options for crossing the Chesapeake Bay.



The line segment from the western shore of Maryland to the eastern shore of Maryland including the Chesapeake Bay Crossing is projected to be completed by 2012. If this line segment, including the Bay Crossing, is delayed because of permitting, the completion of the other portions of the project will still provide reliability and economic benefit to the Delmarva Peninsula. For example, PHI/Delmarva will try to accelerate the completion of the Salem to Indian River 500kV line segment of the MAPP Project which is currently scheduled for 2013 in-service date. This Salem to Indian River 500kV line segment will increase import capability into Delmarva and Delmarva south. In addition, PHI will work with PJM to identify any short term transmission upgrades required to maintain the reliability of the transmission system until the full MAPP project is completed. The company recently introduced a separate web site for the MAPP project at www.powerpathway.com. This web site will be an important link to our customers going forward and a location where critical questions will be answered and updates posted.

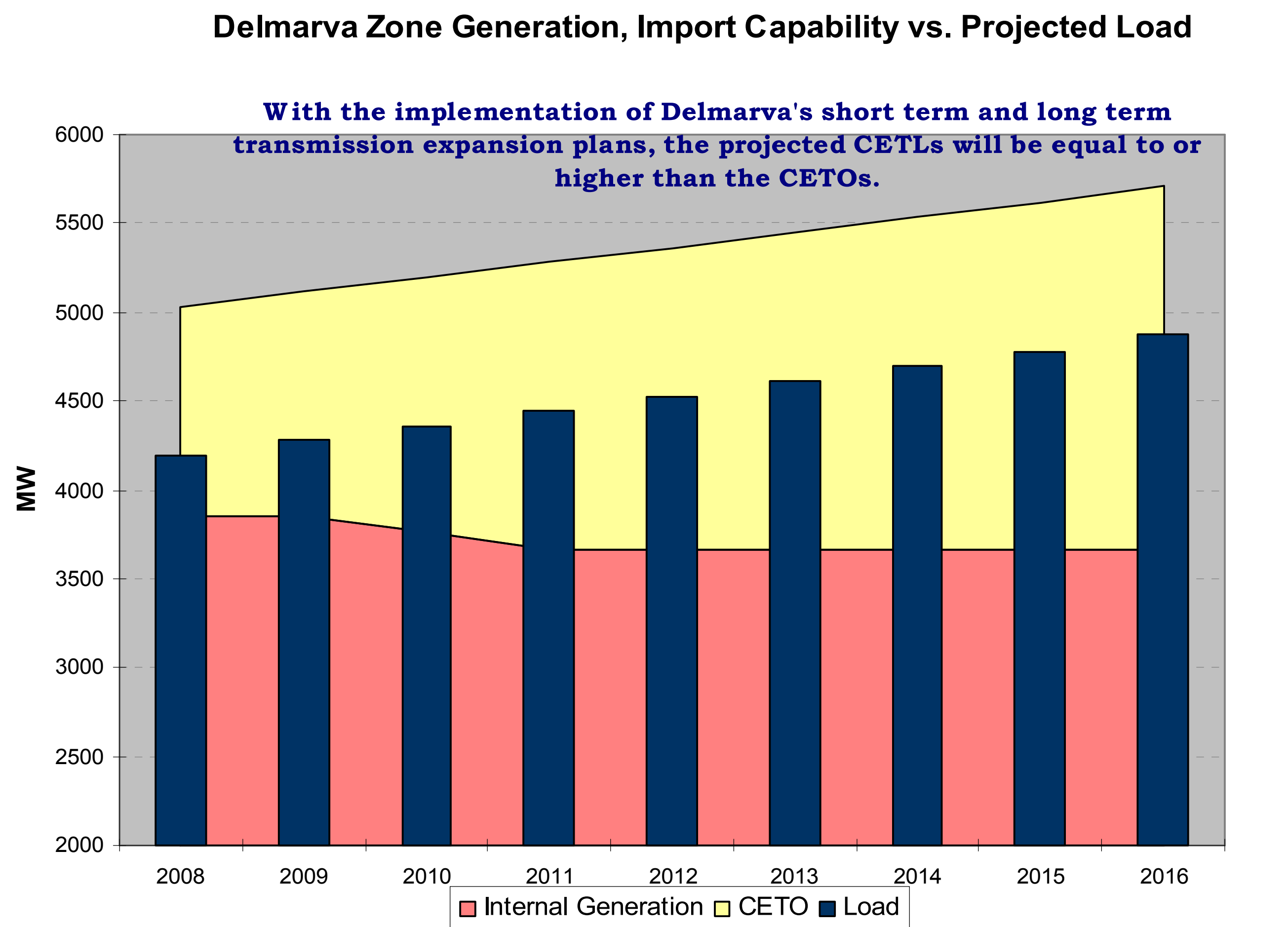
2. Transmission Plans to Address Generation Retirement Scenarios

PJM's rules provide mechanisms to ensure reliability is addressed prior to any generation retirements. NRG has announced the planned retirement of the Indian River Unit #2 in May 2010 and Indian River Unit #1 in May 2011. PJM, with support from Delmarva Power, has developed transmission plans to address these generation asset retirements and those plans were approved by the PJM Board in February 2008. The plans are based on the same rigorous PJM planning process used in the PJM base line to test the transmission system. The transmission enhancements necessary to maintain system reliability after the retirement of Indian River #1 and #2 are shown in the table below.

Retirement of Indian River #1 and #2

Recommanded Upgrades (Based on PJM CETO Analysis)	System Need Date	Estimated Cost ($MM)
Rebuild Mt. Pleasant to Townsend 138kV	Summer 2010	$3.9
Rebuild Trappe to Todd 69kV	Summer 2010	$12.0
Create a 138kV Ring Bus @ Wye Mills (w/ 2nd 138/69kV Transformer)	Summer 2010	$6.0
Add 30 MVAR 69kV Capacitor at Wye Mills	Summer 2010	$1.8
Add 8.4 MVAR 69kV Capacitor at Grasonville	Summer 2010	$1.3
Add 30 MVAR 69kV Capacitor at Bethany	Summer 2010	$1.8
Add a new 138/12kV Transformer at Bethany	Summer 2010	$4.9
Add a 3rd Indian River 230/138kV Transformer	Summer 2011	$7.3
Total Costs		**$39.0**

When considered on top of generation resources already existing within the PJM Delmarva Zone, the implementation of Delmarva's base reliability plan including the transmission investments identified above to be implemented prior to the scheduled retirements of Indian River Generating Units#1 and #2 will continue to maintain the established PJM regional reliability margins within the Zone. This is shown in the chart below:



Capacity Emergency Transfer Objective (CETO) - is the targeted import capability objective into the area to meet established regional reliability margins. Capacity Emergency Transfer Limit (CETL) - is the estimated/calculated import capability into the area. For purposes of this graph, the projected CETLs are equal to or higher than the CETOs. The 2011/2012 CETL is calculated to be 1737MW. MAPP will add an additional 1000MW of import capability.

In the event that other generation asset retirements are announced in the Delmarva Zone, PJM and Delmarva Power will develop the necessary transmission enhancement plans to ensure the continued reliable operation of the transmission system in the Zone. Delmarva Power has done a preliminary analysis to determine the upgrades that would be required if additional generation were to be retired. That preliminary analysis is shown in the table below.

Transmission Reinforcements	Retirement of Vienna 8 &10	Retirement of Edge Moor 3 & 4 and Vienna 8 &10	Retirement of Indian River 3 & 4 and Edge Moor 3 & 4 and Vienna 8 & 10	Estimated Cost ($MM)
Rebuild Glasgow to Mt. Pleasant 138kV	X	X	X	$5.7
Rebuild Easton to Trappe 69kV	X	X	X	$2.0
Add 25 MVAR 69kV Capacitor at Cool Springs		X	X	$1.5
Add 25 MVAR 69kV Capacitor at Church		X	X	$1.5
Add 30 MVAR 69kV Capacitor at Indian River			X	$1.5
Convert Vienna to Loretto to Piney Grove 138kV lines to 230kV			X	$24.0
Install a 230/138kV Transformer at Loretto and Vienna			X	$10.0
Add 2nd 230kV line from Steele to Vienna			X	$40.0

Notes:
1. Assumes the retirement of Indian River # 1 and # 2.
2. Includes all RTEP-approved plans (including MAPP 500kV).

The last three projects shown in the table are the 230 kV projects that compliment the MAPP project and are presently under study by PJM.

3. **New Regulated Generation in Delaware:**

While Delmarva's base plan is to meet the electrical reliability needs of its Delaware customers through the specific transmission investments identified above, construction of new generation facilities in Delaware could also provide some positive effects to system reliability and potentially provide a hedge on forward electricity prices. If the Commission wants us to do so, and appropriate regulatory assurance for full cost recovery is obtained, Delmarva would consider a commitment to construct and operate a regulated generation assets as a reliability resource.

Under traditional regulation of generation, the cost of the generation asset was allowed in the Company's rate base, the generation asset was subject to regulatory accounting, fuel cost recovery mechanisms were in place and there was no customer choice. Delmarva respectfully submits that these issues be resolved prior to and as part of Delmarva's possible return to regulated generation.

If the Commission was faced with a situation where reliability in the State was threatened due to a lack of generation, generation was the most cost-effective remedy for maintaining reliability, and the market was not forthcoming with new generation projects that would resolve the reliability issue in the State of Delaware, then from the customers' point of view, it may be preferable for the Commission to require Delmarva to own the generating facility, rather than entering into a long-term purchase power agreement with a private developer for a similar generating facility.

While, in an engineering sense, there is no reason to expect that the physical generating facilities developed and owned by Delmarva would vary in any significant way from a similar facility constructed by a private developer and supported by a long-term power purchase agreement, the distribution of the *economic and financial benefits* of a regulated plant may be markedly different. If Delmarva owns the regulated generating facility, the allowed rate of return on the investment will be established by the Commission. Not only would the initial rate of return be set by the Commission when the facility comes into service, but the rate of return can be appropriately adjusted by the Commission as market conditions change over the useful life of the project. By regulating the rate of return, the Commission can insure that the utility does not earn above market returns on the investment.

Under utility ownership, the customer receives the entire economic benefit of plant operation. This occurs because the utility plant will be operated under economic dispatch. This means that the plant is generally operated only when the cost of producing power from the plant is less than the market price of power.[30] Every kWh generated under economic dispatch is 'profitable' to customers in the sense that

[30] The plant would always operate when needed for reliability whether economically dispatched or not.

power from the plant costs less than power purchased from market. These savings from plant operations are directly accrued to customers in reduced energy supply costs.

In summary, if new generation is the most cost-effective way to maintain reliability and the Commission feels that the market is not otherwise on its own providing remedies to this problem, then utility owned generation is a preferable alternative from a customer perspective for the following reasons:

1. The revenue requirement for the generating facility will be regulated by the Commission over the useful life of the generating asset;
2. Under utility ownership, the generating facility would be economically dispatched providing customers with economic benefits relative to market every time the plant was dispatched;
3. As discussed earlier in the report, benefits accrue to customers over the life of the asset, not just over the life of the contract.
4. Utilities are more likely to have stronger credit profiles over the entire life of the generating asset than special purpose entities created in support of a long-term purchase power agreement.

4. Reliability Suggested Path Forward:

The Delmarva Power system meets all national, regional and local reliability standards. Delmarva's base plan is to meet the electrical reliability needs of its Delaware customers through the specific transmission investments identified above. PJM has approved the 500kV portion of the MAPP transmission project that is expected to significantly increase import capability into Delmarva and Delmarva

South. If additional generation units within the Zone are retired, Delmarva will work with PJM to have the additional transmission investments as identified above approved and implemented.

While Delmarva's base plan is to meet the electrical reliability needs of its Delaware customers through the specific transmission investments identified above, the construction and operation of regulated generation assets in Delaware may provide additional reliability and economic benefits to customers. Delmarva Power would be willing to construct and operate a regulated generation facility in Delaware for purposes of further securing reliability and for other customer benefits under either traditional regulation or its functional equivalent if, after analysis, the Commission determines that this path is appropriate. Under traditional regulation of generation, the cost of the generation asset was allowed in the Company's rate base, the generation asset was subject to regulatory accounting, fuel cost recovery mechanisms were in place and there was no customer choice. If the Commission is interested in Delmarva pursuing options related to regulated generation, Delmarva respectfully suggests the following:

1. The Commission direct the Portfolio Working Group described above to additionally propose a regulatory framework for including regulated generation assets in rate base, the mechanism and frequency for fuel and other cost recovery associated with the operation of a regulated generation asset and the implementation of non-bypassable charges or restrictions of customer choice.

2. Concurrently with the initiation of the Portfolio Working Group and if authorized by the Commission, Delmarva conduct a preliminary generation feasibility study to review regulated generation alternatives for Delaware.
3. Assuming that the Commission directs the Portfolio Working Group to review potential regulatory frameworks for regulated generation, the Portfolio Working Group recommendations regarding regulated generation will be included with the application filed by Delmarva regarding the portfolio management rules and regulations.

VII. Energy Efficiency and Demand Response

1. Delmarva's Blueprint Filing, Demand Response and AMI:

> The purpose of this Blueprint for the Future is to set forth Delmarva Power's comprehensive vision of the future and for taking Delmarva and Delmarva's Delaware customers forward into that future - a future where DSM programs, both energy efficiency and demand response, are enabled by new technology investments to best meet Delmarva's Delaware customer energy needs.
>
> Delmarva's Blueprint Filing – February 6, 2007
> PSC Docket No. 07-28

Energy efficiency and demand response are important elements of Delaware's energy future. The Supporting Documentation to the 2006 IRP filed January 8, 2007 contained a detailed analysis of a number of Demand Side Management ("DSM") programs and concluded that the implementation of 25 of these programs would lead to savings of 9% of Delmarva's load requirement and 6% of its capacity requirement by 2015.

On February 6, 2007 Delmarva submitted its "Blueprint for the Future" a program designed to address two important local and national challenges; the rising cost of energy and the impact of energy use on the environment.

The three key components of the Blueprint filing are: 1) the installation of an Advanced Metering Infrastructure ("AMI"); 2) the establishment of a range of Demand Side Management Programs ("DSM") and 3) the initiation of a Billing Stabilization Adjustment ("BSA" – also know as "Revenue Decoupling").

As of this filing, Delmarva is planning to participate in a March 17, 2008 PSC sponsored workshop for the involved parties to provide guidance on both PSC Docket No. 07-28 (Blueprint for the Future) and PSC Regulation Docket No. 59 (Revenue Decoupling – opened March 20, 2007).

Also, since that Blueprint submittal, the State of Delaware has established the Sustainable Energy Utility ("SEU"), which has taken responsibility for initiating and managing energy efficiency and conservation programs in the state. Twenty three of the 25 DSM programs recommended in the December 1, 2006 IRP compliance filing are classified as energy efficiency programs; the remaining two, residential and commercial smartstats (i.e. "smart" thermostats), are classified as demand response ("DR") programs. Going forward, it appears that the SEU will be responsible for the design, implementation, and monitoring of energy efficiency programs and Delmarva will be responsible for DR programs.

The Delaware Sustainable Energy Utility has provided Delmarva Power with projected energy and peak demand reductions attributable to their planned energy efficiency and conservation programs over the period of 2008 through 2016. The SEU projected Delaware-wide energy and peak demand savings. These figures were adjusted to Delaware Delmarva Power savings based upon the Company's percentage of Delaware annual energy sales and peak electricity demand. Table DSM-1A below compares the Delmarva demand response projections from the December 1, 2006 IRP filing with those from the Blueprint. Table 1B compares the projected energy efficiency and conservation program demand and energy savings from the December 1, 2006 IRP filing with the current SEU projections. Because the SEU projections do not include the projected savings attributable to Demand Response programs the Delmarva figures in Table DSM -1B are shown net of Demand Response savings so as to provide an "apples to apples" comparison.

Table DSM – 1A

Comparison of DPL December 1, 2006 demand response savings projections with Blueprint projections

Demand Response Programs

	kW		MWH	
	Original	Updated	Original	Updated
2008	12,280	28,005	333	333
2009	25,329	46,054	687	737
2010	40,365	63,590	1,095	1,170
2011	45,892	172,158	1,246	6,604
2012	52,176	201,107	1,417	14,349
2013	59,320	244,471	1,611	22,537
2014	67,442	275,045	1,832	30,407
2015	76,677	302,878	2,084	38,212
2016	79,295	307,997	2,155	38,308

Table DSM – 1B

Comparison of DPL December 1, 2006 IRP energy efficiency savings projections with February 2008 SEU

Energy Efficiency Programs

	kW		MWH	
	Original	SEU	Original	SEU
2008	4,022	0	15,690	0
2009	8,035	25,237	31,995	41,085
2010	12,193	51,420	48,453	83,729
2011	15,931	61,144	60,567	99,542
2012	20,545	71,196	78,829	115,933
2013	26,219	78,002	102,720	127,012
2014	33,175	81,330	133,917	132,460
2015	41,677	86,680	175,962	141,145
2016	48,385	99,879	203,112	162,634

As the SEU has now assumed responsibility for energy efficiency and conservation programs in the State of Delaware, the remaining discussion in this section of the IRP update provides an update on DPL's demand response strategy.

There are two types of demand response programs; Direct Load Control ("DLC") and Dynamic Pricing ("DP"). In general, demand response programs are designed to let customers make choices about their energy use – how much they use and when they use it. The continuing decline in information processing costs and the growing penetration of high-speed internet to the home have dramatically changed the nature and potential of DR programs since their introduction 20 years ago.

Most modern DR programs combine elements of Advanced Metering Infrastructure ("AMI') and dynamic pricing programs to give utility operators and homeowners/ building operators up-to-date information on energy prices and the technology for advanced and (often) remote control of a number of energy using devices in the home or office.

The Federal Energy Regulatory Commission staff has defined **AMI** as:

> ...a metering system that records customer consumption (and possibly other parameters) hourly or more frequently and that provides for daily or more frequent transmittal of measurements over a communication network to a central collection point. AMI includes the communications hardware and software and associated system and data management software that creates a network between advanced meters and utility business systems and which allows collection and distribution of information to

customers and other parties such as competitive retail providers, in addition to providing it to the utility itself.[31]

It is important to note the two way communication capability of an AMI system, as communicating rate and energy use information to the customer is as important as the communication of customer use information to the utility.

AMI systems are often implemented in conjunction with dynamic pricing programs. These programs can be broadly defined as rate structures based on "real time" energy production prices. Under these programs customers have current (in some cases, day-ahead) information on energy prices and the ability to alter energy use accordingly. For example, on a hot and humid weekday summer afternoon, customers participating in a DP program would know that high rates would be in affect for some peak period and thus would have the incentive to reduce electric energy use during that period.

The ability to reduce electric energy use in the home or office is also driven by technology. A variety of home/office energy "management" systems are being developed by both established and entrepreneurial companies who sense a large market potential for energy savings systems.

These technologies support both direct load control and dynamic pricing programs. For example, modern AMI meters and smartstats have internal communication capabilities. Under a DLC program, the utility could use that communication function to cycle off a home air conditioner during a peak period (assuming the homeowner agreed to participate in such a program). Today's

[31] FERC, *2007 Assessment of Demand Response and Advanced Metering (FERC Staff Report)* Appendix A (Glossary)

technology allows more choices in program design than the old Energy for Tomorrow program: further, unlike the older programs, with AMI the utility can monitor in real time the affect of the DLC program.

Alternately, under a dynamic pricing program, a homeowner could program the smartstat to cycle off at a certain pricing point, with the pricing signal coming from the utility over the communications infrastructure. In addition, other home appliances, - e.g. refrigerators, pool pumps –are being designed to respond to an energy price signal.

Through the new metering and communications capabilities made possible by AMI installation, DPL expects to continue to operate and introduce new programs designed to reduce peak summer electricity load during periods of high electricity demand. As noted above, DPL included two specific demand response programs (of the 25 DSM programs) in its original IRP filing. These are described below.

- **Residential Smart Thermostat Program**
  - -- a new voluntary smart thermostat program whereby residential customers' central air conditioning load can be reduced by DPL via a programmable thermostat capable of receiving control signals by the utility. The new thermostats are expected to reduce annual energy consumption when they are set to automatically adjust temperature settings. Two way communications to the smart thermostats will be supported through DPL's planned deployment of advanced metering.

- **Non-Residential Smart Thermostat Program**

-- a new voluntary smart thermostat program whereby non-residential customers' package air conditioner load is reduced by DPL via a programmable thermostat capable of receiving control signals by the utility. The new thermostats are expected to reduce annual energy consumption when they are set to automatically adjust temperature settings. Two way communications to the smart thermostats will be supported through DPL's planned deployment of advanced metering.

In August 2007, Delmarva submitted its Advanced Metering Business Case Including Demand Side Management Benefits and, in September, a public workshop was held by the Hearing Examiner to discuss the Business Case. Delmarva augmented that Business Case with a paper prepared on PHI's behalf by the Brattle Group titled, Quantifying Customer Benefits from Reductions in Critical Peak Loads from PHI's Proposed Demand-Side Management Programs.

The Brattle Group was retained by PHI to estimate the value to customers of load reductions resulting from PHI's proposed investments in demand-side management initiatives, including energy efficiency, direct load control, and deployment of advanced metering infrastructure across each of the PHI utility companies, including Delmarva.

The following discussion and Delaware specific data are excerpted from the AMI Business Case and the Brattle submittals.

a. Load Reductions

Load reductions in Delaware associated with AMI-enabled direct load control are taken directly from PHI's most recent Blueprint Filing for its DSM programs.

Load reductions in Delaware associated with an AMI-enabled dynamic pricing program called critical peak pricing ("CPP") were estimated using the PRISM model, which is based on empirical data from the California Statewide Pricing Pilot and is calibrated to the load characteristics of residential and small C&I customers in Delmarva Delaware. Assuming a CPP program similar to PEPCO DC's current CPP pilot becomes the default rate structure with 80% of eligible customers participating, the resulting load reductions would likely be quite substantial. The load reductions would be less substantial if participation were voluntary.

Delmarva's BluePrint filing recommended an additional demand response program not included in the IRP. This program, the Non-Residential Internet Platform for Load Curtailment, is designed to let larger commercial, government, institutional, agricultural and industrial customers [those capable of reducing load by 100kW during a summer weekday afternoon] participate in PJM load response programs. After three years of operations, this program is estimated to have the potential to curtail peak load demand by 10MW.

Finally, the Energy for Tomorrow ("EFT") program is Delmarva's legacy DLC program which we expect to continue for now and to replace over time (in conjunction with the installation of AMI) by focusing solely on the SmartStats program.

Under the EFT program, Delmarva will offer residential distribution customers with central air conditioning or central heat pumps the choice of the installation of an outdoor cycling switch or an indoor smart programmable thermostat. Customers will have the opportunity to choose three cycling options. The choice of either an outdoor switch or an indoor smart programmable thermostat will increase the number of customers willing to participate in the program in the near-term.

All Delmarva customers will receive benefits from the program through the mitigation of regional PJM wholesale energy and capacity prices, avoidance of generation supply costs and improved reliability of supply.

At the time of AMI deployment, Delmarva will begin to migrate previously installed direct load control equipment to two-way communications through the AMI.

The following table summarizes the expected peak load demand and energy reductions from the programs described above:

Blueprint Peak Load & Energy Reductions

	Year	2008	2009	2010	2011	2012	2013	2014	2015	2016
Dynamic Pricing	MW	-	-	-	90	90	91	91	91	91
	EFT Participants	40,844	40,844	40,844	32,844	24,844	16,844	8,844	-	-
	Smart Stat Part.	-	-	-	11,000	26,570	26,570	26,570	26,570	73,820
	EFT kW	15,725	15,725	15,725	12,645	9,565	6,485	3,405	-	-
	SS kW	-	-	-	13,621	32,902	32,902	32,902	32,902	91,411
Res. DLC	MWh	-	-	-	5,258	12,700	12,700	12,700	12,700	35,286
	Participants	-	-	-	-	500	2,555	3,000	3,000	3,000
	kW	-	-	-	-	3,965	20,261	23,790	23,790	23,790
Small Com. DLC	MWh	-	-	-	-	107	547	642	642	642
	kW	-	5,000	7,500	10,000	12,500	15,000	17,500	20,000	22,500
Internet Platform	MWh	-	50	75	100	125	150	175	200	225

b. Decoupling

Under the current utility rate structure, because the distribution utility's costs do not change when sales increase or decrease, the distribution utility's profits increase when sales increase and, conversely, decrease when sales decrease. This situation creates a disincentive (or unintended systemic penalty) for the distribution utility to help its customers conserve energy, since customer conservation will reduce the distribution utility's sales and thus its profits. This disincentive/penalty can be removed by decoupling distribution utility revenues from the level of customer sales, so that the distribution utility is not harmed when customers conserve energy.

Even if distribution utility revenues are decoupled from sales, customers' total bills will still be reduced when customers conserve, since the energy portion of the bill, which accounts for over 75% of the total, will still decrease.

The decoupling mechanisms also ensure that the distribution utility only receives the amount of revenue that the Commission has determined is appropriate. There are a number of rate mechanisms that will effectively decouple the distribution utility's revenues from the sales of electricity, including the Company's proposed Bill Stabilization Adjustment mechanism. The adoption of a rate decoupling mechanism allows the Company to aggressively promote energy conservation without sustaining the unintended, yet systemic, penalty under the current rate structure.

Decoupling mechanisms are effective means of addressing the impact on a utility's earnings of energy efficiency and demand response programs, thereby aligning the utility's interests with public policy goals. Delmarva's decoupling proposal addresses the significant loss of fixed cost recovery expected to result from expanded energy efficiency programs and improves the overall alignment of rates with cost structure.

While it is clear that energy efficiency programs will result in an under-recovery of authorized fixed costs, mechanisms to address that must continue to ensure that rate structures should match, to the extent feasible, the underlying utility cost of service. This principle guides all of utility ratemaking:

- it is the reason why such focus is given to the appropriate level of revenue requirement (utilities are allowed the opportunity to recover all allowable costs, including a fair rate of return) ;
- it is the reason why the allocation of the revenue requirement to each class is determined by the load characteristics, number of customers, and other cost drivers for each class (so that the allocation of overall cost to each class is driven by a calculation of the share of total cost incurred by each class);
- finally, it is the reason why rate designs generally have multiple components that reflect the underlying cost (the customer charge is an approximation of the cost required to perform basic customer service functions, demand charges reflect the fixed costs incurred to serve load, and usage charges reflect the costs of different levels of energy usage).

These principles are consistent with the Staff's rate design policy goals and objectives filed on August 15, 2007 in Regulation Docket No. 59. A rate design based on these principles, which actually reflects the true distribution of fixed and variable costs, is fair to all customers. It insures that customers pay for the costs associated with their usage and not the usage of others. For example, suppose the company had high variable costs, and low fixed costs, but charged all customers a single fixed charge. In that instance, low usage customers would subsidize higher usage customers (since the variable costs associated with high usage would be spread in the fixed charges, resulting in an average price that was greater than the average cost associated with low usage customers).

Rate designs that reflect the underlying costs are also efficient. When a customer chooses to increase load and, therefore, the utility must install additional equipment to meet the increase in the customer's needs, the utility incurs additional investment and fixed operating costs associated with meeting that load. Efficient rate designs would reflect this cost to the maximum extent possible. If the rate design were not cost based, the usage component of the rate might be significantly greater, or significantly less than the cost the utility would incur to meet the increase in usage. If the rate were above the cost, customers would be charged amounts greater than the increase in cost incurred by the utility. If the rate were below cost, customers would pay less than the increase in cost, and would be encouraged to consume an excess amount. Thus, rate designs based upon cost are both fair, and efficient.

One alternative to this problem would be to recover fixed costs through fixed charges commonly referred to as a straight fixed-variable rate design. The Staff's report recommends such a design. From a pure economic perspective this type of rate design provides the most effective cost signals, but such a method could result in very significant increases to smaller customers, since they do not typically have demand meters that can be used to bill for the fixed charges. The BSA addresses this problem by essentially fixing the revenue requirement for each class. If average usage is greater than the fixed amount in the test year, the BSA adjustment will reduce bills for all customers in that class. If average usage is less, the BSA will increase the delivery portion of the bill for customers, limited to the 10% cap. The BSA does not penalize smaller customers or reward larger ones, but treats each customer in the class equally.

The BSA goes a long way to accomplish these objectives. The BSA"decouples" revenue from unit sales consumption and ties the growth in revenues to the growth in the number of customers. Some advantages of the BSA are that it (i) eliminates revenue fluctuations due to weather and changes in customer usage patterns and, therefore, provides for more predictable utility distribution revenues that are better aligned with costs, (ii) provides for more reliable fixed-cost recovery, (iii) tends to stabilize customers' delivery bills, and (iv) removes any disincentives for the regulated utilities to promote energy efficiency programs for their customers, because it breaks the link between overall sales volumes and delivery revenues.

There are several methods associated with decoupling besides the Company's proposed BSA and the straight fixed-variable rate design discussed above. While these two methods are discussed in more detail in Appendix C, the table on the next page provides a high level comparison of the different methods, along with some pros and cons associated with each.

Different Decoupling Methods

Mechanism	Characteristics	Revenue Drivers Between Rate Cases	Pros	Cons
Traditional Regulation	Revenues set to earn authorized return. Volumetric rates recover a portion of fixed costs	Any changes in usage	Long history of acceptance, mechanism well understood.	- Recovery of fixed costs through volumetric rate results in over/under recovery. Improper price signal. - Doesn't remove disincentive to promote conservation
Weather Decoupling	Compares weather normalized current period revenues to test period revenues	Change in usage unrelated to weather	Widely adopted, straightforward to calculate and administer	- Adjusts revenues for impacts of weather only. - Improper price signal. - Doesn't remove disincentive to promote conservation
Revenue Decoupling (Company Concept)	Decouples revenue from sales, re-couples to another metric, typically number of customers	Change in number of customers	-Adjusts revenues for all impacts on a per customer basis, removes disincentive to promote energy conservation -Better price signal	-Limited long term experience (except CA) -Recovery of fixed costs through volumetric rates.
Return Stabilization	Resets revenues to stay within a band around an authorized return	Change in cost or revenues resulting in returns outside earnings band	Controls for changes in both costs and revenues	-May reduce incentive to control costs - Recovers fixed costs through volumetric rates
Fixed/Variable Rate Design (Staff Concept)	Recovers fixed costs through a fixed charge, variable costs through a volumetric charge	Any change in usage	Economically efficient, aligns revenues with underlying costs, sends better economic price signal	-May result in significant increases for low usage customers. -Reduces customer incentive to conserve.

In conclusion, as part of its Blueprint for the Future filing and included in the Regulation Docket No. 59 proceeding, Delmarva has proposed a decoupling mechanism that should be implemented as soon as possible to enable the Company and the state of Delaware to move forward in alignment on the goal of reducing energy consumption. In developing the BSA, Delmarva went to great lengths to select the best program for Delaware. Delmarva's development of the BSA was the result of a careful review of the history of decoupling, the need to achieve successful reduction in load, the needs of Delaware customers, and problems posed by the present volumetric distribution rate designs. Delmarva's BSA was developed to benefit customers while removing the systematic conservation penalty that utilities currently face.

2. Suggested Path Forward Demand response programs provide Delmarva's customers with a good opportunity to take control of their individual energy consumption. Consistent with this Delmarva recommends that the Commission take the following action:

1. Approve Delmarva Power's plan to establish an Internet-based Portal to the PJM Demand Response Market. Larger commercial, government, institutional, agricultural and industrial customers - those capable of reducing load by 100kW during a summer weekday afternoon – are sophisticated energy users who can take advantage of PJM's market based conservation offerings.
2. Approve Delmarva Power's proposed establishment of new residential and small commercial customer direct load control programs. These

programs have worked in the past – new technologies provide an even greater opportunity to lower peak demand.

3. Establish cost recovery methods for new demand response initiatives and deployment of advanced metering. This step is critical to advancing these programs.
4. Approve a decoupling mechanism for Delmarva. This mechanism decouples revenue from sales and thus removes disincentives to implementing demand side management programs.
5. Accept the Advanced Metering Infrastructure recommendations from the Blueprint filing – including the creation of an AMI Working Group to review and report on AMI implementation issues. AMI is the principal technology driver for both demand response and critical peak pricing programs – but there are many program design issues, including the communications infrastructure, which must be settled before program implementation.
6. Charter the AMI Working Group to examine alternative dynamic pricing options, such as critical peak pricing. This program would allow Delaware's electric energy consumers to actively manage their own energy use. In an "interactive" and "internet" age, well informed consumers will make intelligent decisions about their energy use patterns.

Appendix A

Delaware Eligible Renewable Energy Resources

"Eligible Energy Resources" means the following energy sources located within the PJM region or imported into the PJM region and tracked through the PJM Market Settlement System:

- Solar Photovoltaic Energy Resources means solar photovoltaic or solar thermal energy technologies that employ solar radiation to produce electricity or to displace electricity use
- Electricity derived from wind energy;
- Electricity derived from ocean energy including wave or tidal action, currents, or thermal differences;
- Geothermal energy technologies that generate electricity with a steam turbine, driven by hot water or steam extracted from geothermal reservoirs in the earth's crust;
- Electricity generated by a fuel cell powered by Renewable Fuels;
- Electricity generated by the combustion of gas from the anaerobic digestion of organic material;
- Electricity generated by a hydroelectric facility that has a maximum design capacity of 30 megawatts or less from all generating units combined that meet appropriate environmental standards as determined by DNREC (see DNREC Regulation's Secretary's Order No. 2006-W-0027);
- Electricity generated from the combustion of biomass that has been cultivated and harvested in a sustainable manner as determined by DNREC, and is not combusted to produce energy in a waste to energy facility or in an incinerator (see DNREC Regulation's Secretary's Order No. 2006-W-0027);
- Electricity generated by the combustion of methane gas captured from a landfill gas recovery system; provided, however, that:
- Increased production of landfill gas from production facilities in operation prior to January 1, 2004 demonstrates a net reduction in total air emissions compared to flaring and leakage;

- Increased utilization of landfill gas at electric generating facilities in operation prior to January 1, 2004 (i) is used to offset the consumption of coal, oil, or natural gas at those facilities, (ii) does not result in a reduction in the percentage of landfill gas in the facility's average annual fuel mix when calculated using fuel mix measurements for 12 out of any continuous 15 month period during which the electricity is generated, and (iii) causes no net increase in air emissions from the facility; and

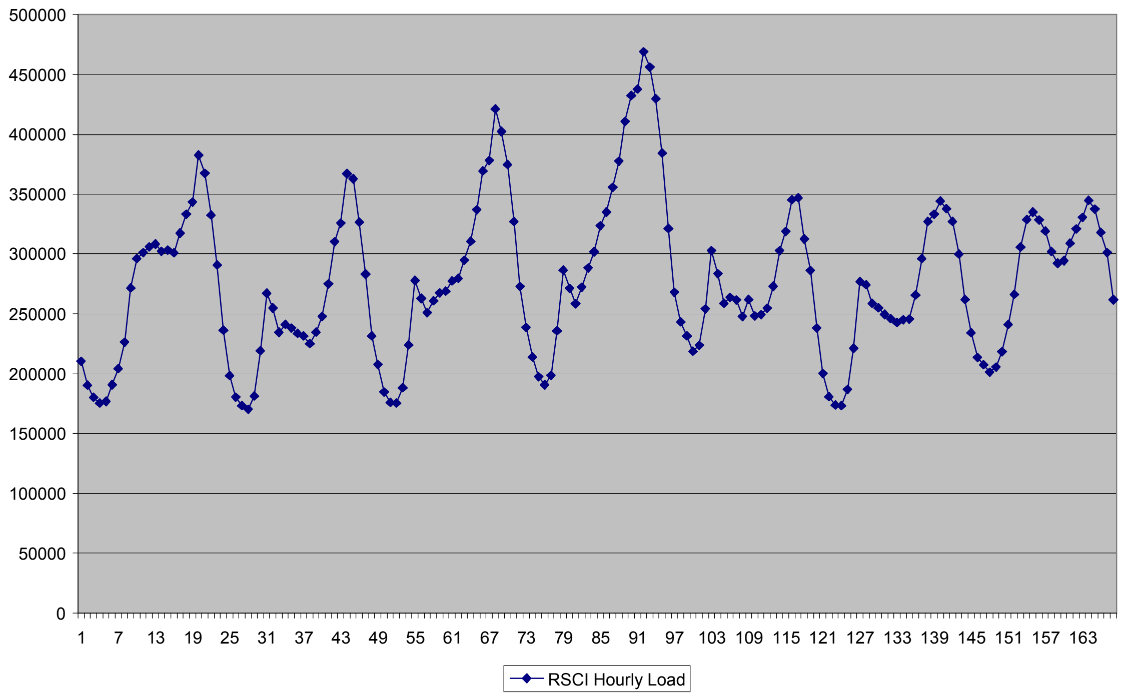
- Facilities installed on or after January 1, 2004 meet or exceed 2004 Federal and State air emission standards, or the Federal and State air emission standards in place on the day the facilities are first put into operation, whichever is higher.

Appendix B

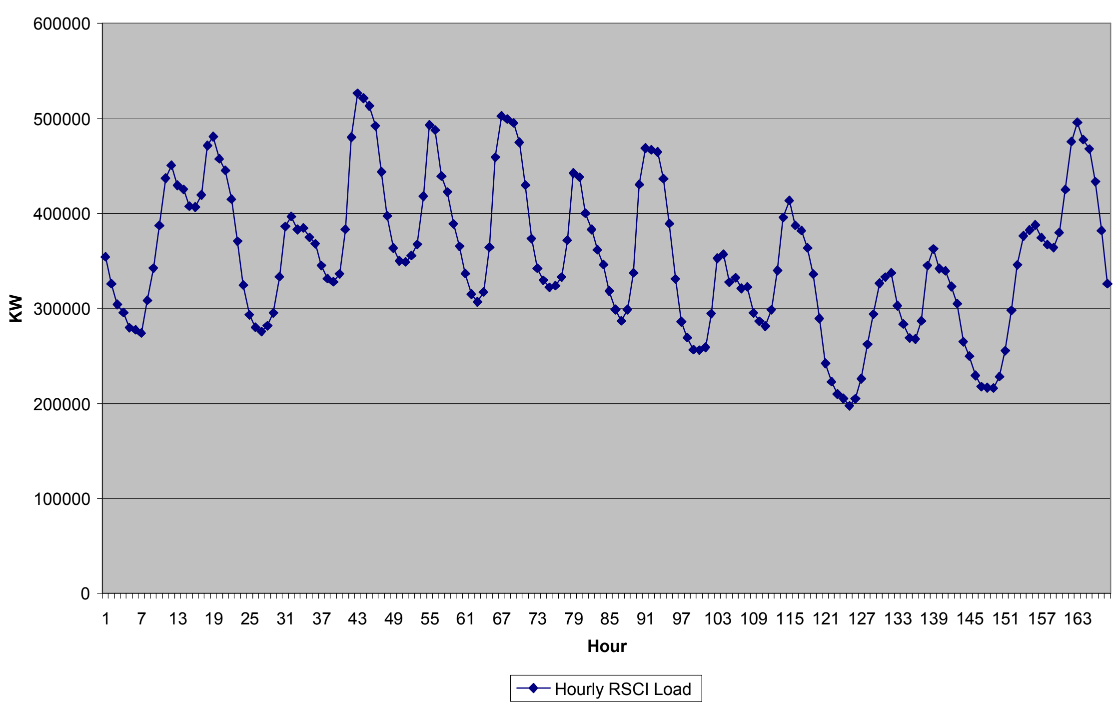
Examples of RSCI Load Variability

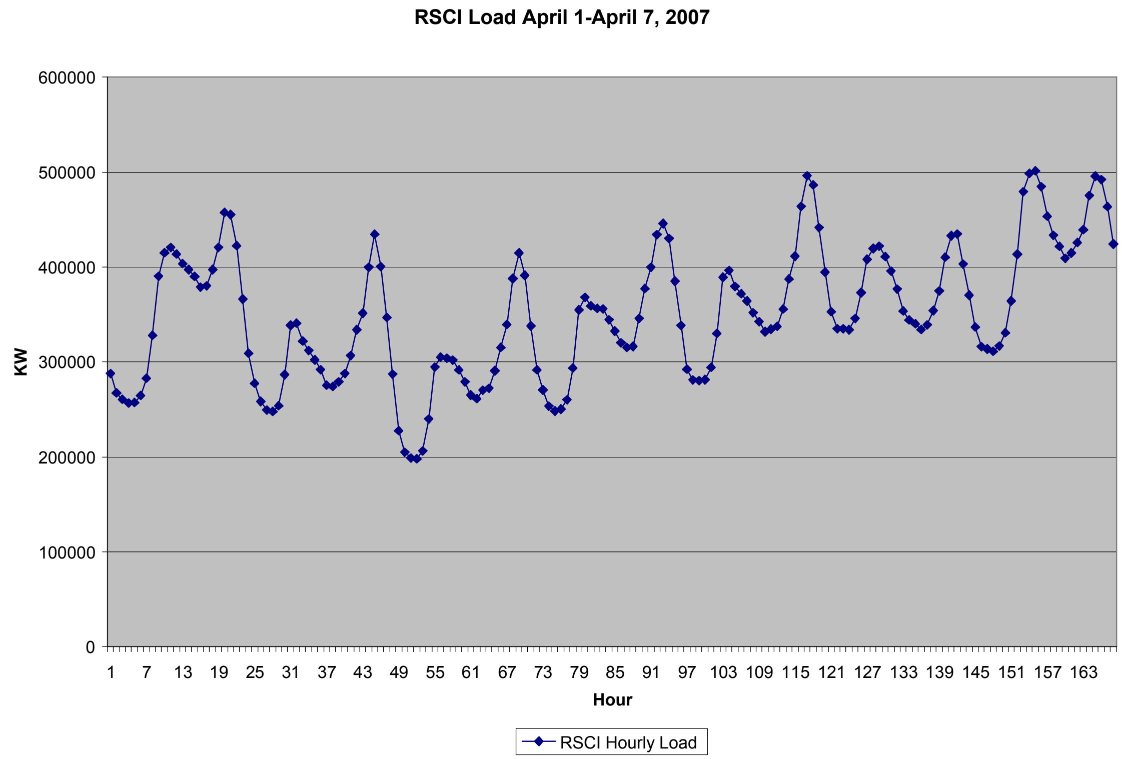
The following charts show the load profile of RSCI customers for the weeks of October 1 –October 7, 2006, January 1 –January 7, 2007, April 1 – April 7, 2007 and July 1 – July 7, 2007. The purpose of these charts is to illustrate the variable nature of the RSCI customer load. In each of the periods shown on the charts, the load differences among days are observable as well as the daily differences between minimum and maximum loads. A resource portfolio designed to manage the procurement needs of RSCI customers must necessarily manage this variability and use spot purchases to balance the fixed resources in the portfolio with the varying load.

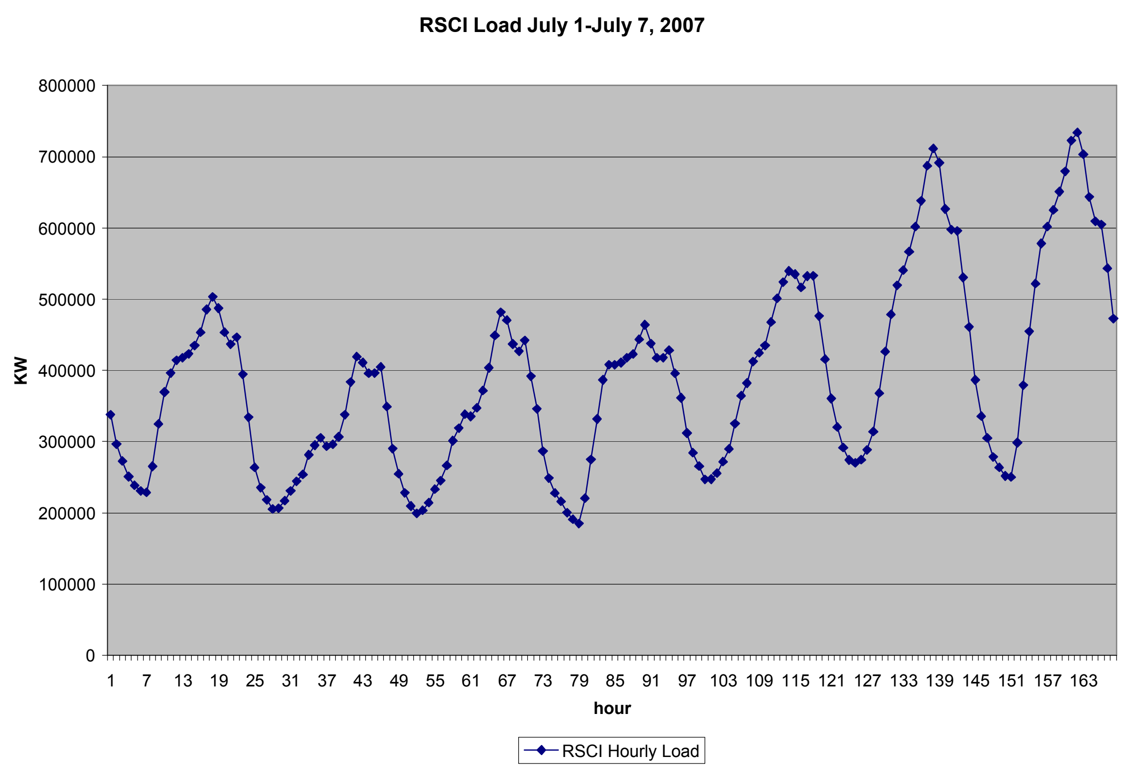
RSCI Load Oct 1 - Oct 7, 2006



RSCI Load Jan 1 - Jan 7, 2007




RSCI Load April 1-April 7, 2007
KW
Hour
RSCI Hourly Load


RSCI Load July 1-July 7, 2007
KW
hour
RSCI Hourly Load

APPENDIX C

Decoupling Distribution Revenue From Sales

Decoupling distribution revenue from sales is an important enabling mechanism for Demand Response and energy efficiency programs. As the Company stated in its August 15, 2007 comments filed in the generic decoupling rulemaking proceeding, Docket No. 59, which the Company incorporates herein by reference, in Delaware, the issue of decoupling was first brought to the forefront in testimony by the Staff in Delmarva's last electric base rate case, PSC Docket No. 05-304, testimony of Robert J. Howatt. Mr. Howatt's recommendation that a decoupling mechanism be explored for Delmarva is consistent with the position of the Mid-Atlantic Distributed Resources Initiative ("MADRI"). MADRI was established in 2004 by the public utility commissions of Delaware, District of Columbia, Maryland, New Jersey and Pennsylvania, along with the U.S. Department of Energy ("DOE"), U.S. Environmental Protection Agency ("EPA"), Federal Energy Regulatory Commission ("FERC") and PJM Interconnection. MADRI's goal is to remedy retail barriers to the deployment of distributed generation, demand response and energy efficiency in the Mid-Atlantic region. *See* http://www.energetics.com/madri/.

MADRI's position with respect to the need to address the conservation disincentive was addressed in the testimony of Commissioner Rick Morgan of the Public Service Commission of the District of Columbia in his testimony before the Federal Energy Regulatory Commission.

[W]e are looking at the removal of regulatory barriers at the state level that prevent the benefits of DR [demand response] from being achieved, such as replacing traditional rate designs with dynamic pricing and also tweaking the ratemaking formula with a revenue stability mechanism to remove the utilities' incentive to maximize sales.

Testimony of Rick Morgan, *FERC Demand Response and Advanced Metering Conference*, Docket No. AS06-02-000, at pg. 2 (January 25, 2006)

The United States Department of Energy has also made its position in support of decoupling clear:

Decoupling is amongst the most important things you as legislators can do immediately to affect our nation's energy balance, enhance our energy security, and alleviate price pressure for the citizens in your states. Bu decoupling a utility's sales from their revenues, you will encourage the greater use of distributed generation and increase the incentive for utilities to pursue energy efficiency, demand-side management and renewable energy.
Many states have already successfully moved in this direction and they should be applauded, but we all recognized that so much more can be achieved by aligning the interest of the private sector and citizenry at large on the same side of the table.

DOE Asst. Secretary Alexander Karsner's speech to Natl. Conf. of State Legislators, August 16, 2006.

In response to the Docket 05-304 testimony of Mr. Howatt, Delmarva undertook a careful review of the history of decoupling, the need to achieve successful reduction in load, the needs of Delaware customers, and the challenges faced by Delmarva customers, the Commission and Delmarva under the present volumetric delivery rate design. Delmarva studied various decoupling programs and the experiences of other jurisdictions. This has all led to the development and filing of the Company's BSA in the Company's August 31, 2006 natural gas base rate case which formed the backdrop for the BSA that was included in the Company's Blueprint for the Future filing made on February 6, 2007 and ultimately the Commission's Regulation Docket No. 59 that was initiated on March 20, 2007 in Commission Order No. 7153 - as referenced earlier history is contained in the Company's August 15, 2007 comments in Regulation Docket No. 59 that is incorporated herein by reference.

In today's world, utility customers are better off financially when they use less electricity and natural gas. However, due to the current volumetric rate structure, which ties the amount of a utility company's revenue to the amount of commodity consumed, Delaware utilities are better off financially when their customers use more energy. This inherent conflict is recognized by many as a roadblock to a successful, fair and robust portfolio of programs to help reduce energy usage by customers. It is true that Delmarva can be ordered to develop programs for our customers that will result in reduced consumption and reduced revenues, and Delmarva has, in fact, supported conservation and demand response, but this is not the way to achieve the most successful long term solutions to this problem. Delmarva believes that there are so many ways it can be an active and leading partner in the conservation and demand response effort to reduce consumption by our customers that aligning the utility's interests with the needs of its customers is by far the superior method to achieve the best results. This has also been supported by a nationally recognized leader in conservation efforts, the National Resources Defense Council ("NRDC") in their June 16, 2007 comments filed in Regulatory Docket No. 59.

To provide more detail on why this is important, we need to look at the basis for distribution rate design. Current distribution rate designs are based primarily upon the sale of kilowatt hours of electricity and units of natural gas, even though delivery only utilities like Delmarva are no longer engaged in generating electricity or producing natural gas for distribution. An important function in setting rates for a delivery only utility, such as Delmarva, must be recovery of costs that are far more fixed in nature than they were when Delmarva was engaged in the business of both delivery and generation of the commodity.

Current distribution rate designs are based primarily upon the sale of kilowatt hours of electricity and units of natural gas, even though delivery only utilities like Delmarva are no longer engaged in generating electricity or producing natural gas for distribution. An important function in setting rates for a delivery only utility, such as Delmarva, must be recovery of costs that are far more fixed in nature than they were when Delmarva was engaged in the business of both delivery and generation of the commodity.

Prior to utility restructuring, most integrated utilities had significant components of both fixed and variable costs. Thus, rate designs were developed based upon that cost structure. For larger customers with demand meters, rate designs typically had a fixed customer charge, a demand charge that recovered fixed costs, and a usage charge that reflected the variable costs (such as the cost of the commodity). For smaller customers, without demand meters, many utilities developed block structured usage rates. In these, the fixed costs were largely recovered with low levels of consumption, and the “tail blocks” recovered just the variable charges.

With restructuring, however, many utilities, including DP&L, provide only the delivery/distribution function, with costs that are largely fixed. The old rate designs are no longer appropriate, particularly for non-demand metered customers. A customer who uses more electricity than average pays an appropriate amount for the commodity, but pays too much in delivery charges (since the usage charge is designed to recover average levels of fixed costs for average level of use customers). A customer who uses less electricity than average appropriately saves on the commodity portion of the bill, but pays less than her share of fixed costs.

Another significant problem is that the revenue requirement – as determined by the PSC – will not be appropriately recovered unless the usage levels during the rate in effect period exactly match usage during the test period. If commodity sales are greater than estimated, there will be an over collection. If commodity sales are less than estimated, the revenue requirement will not be met. Thus, the significant effort by utilities and the Commission to determine the correct and appropriate level of revenues (that is, the level of allowable costs plus a fair return) is for naught.

The problem, matching of revenue streams to fixed and variable operating costs, still remains a basic issue with distribution utilities nearly a century later, including the electric and gas utilities of Delaware. The constraints on siting distribution and transmission facilities, as well as the escalating minimum requirements on operation and maintenance of facilities, are increasing the fixed costs of operations and usually without any corresponding revenue generation opportunity to offset these costs absent increases in rates for service. Increasing regulatory mandates for safety, homeland security, environmental protection, financial reporting, operating proficiency, and customer care, all impose additional costs with no increase in revenue, absent rate increases, as sales are not expanded by these requirements.

One result of rising energy prices and rising ambient temperatures has been a resurgence of interest in DSM and alternative energy sources to improve the efficiency of energy use and reduce our reliance upon fossil fuels. Dramatic rises in the market prices of fuels since 2000, the concern about the environmental effects of burning fossil fuels, and the removal of rate caps have brought us to reconsider these resources. Unfortunately, evaluation of DSM and alternative energy places the utility in the middle of issues not of its making and beyond its control, but which impact the utility in the ratemaking process.

The result of the current mismatch between cost structure, and rate designs, is that rates no longer tie to the revenue requirement. They can also produce results that are unfair to customers. An alternative or innovative rate design, such as our proposed BSA will mitigate these problems. The fact is that in a world where utilities are no longer engaged in the production of the commodity, tying cost recovery to volumetric sales of a commodity no longer makes sense, regardless of the enormous concern Delaware and the world faces with respect to the drastic need to conserve. When the issue of conservation is added to the mix, the inappropriate nature of the current rate structure for delivery only utilities becomes even more apparent.

It is a long-standing principle of rate design that rates should reflect the underlying utility cost of service. This principle guides all of utility ratemaking:

- it is the reason why such focus is given to the appropriate level of revenue requirement (utilities are allowed the opportunity to recover all allowable costs, including a fair rate of return) ;
- it is the reason why the allocation of the revenue requirement to each class is determined by the load characteristics, number of customers, and other cost drivers for each class (so that the allocation of overall cost to each class is driven by a calculation of the share of total cost incurred by each class);
- finally, it is the reason why rate designs generally have multiple components that reflect the underlying cost (the customer charge is an approximation of the cost required to perform basic customer service functions, demand charges reflect the fixed costs incurred to serve load, and usage charges reflect the costs of different levels of energy usage).

We also believe that these principles are consistent with the Staff's rate design policy goals and objectives filed on August 15, 2007 in Regulation Docket No. 59. A rate design based on these principles, which actually reflects the true distribution of fixed and variable costs, is fair to all customers. It insures that customers pay for the costs associated with their usage and not the usage of others. For example, suppose the company had high variable costs, and low fixed costs, but charged all customers a single fixed charge. In that instance, low usage customers would subsidize higher usage customers (since the variable costs associated with high usage would be spread in the fixed charges, resulting in an average price that was greater than the average cost associated with low usage customers).

Rate designs that reflect the underlying costs are also efficient. When a customer chooses to increase load and, therefore, the utility must install additional equipment to meet the increase in the customer's needs, the utility incurs additional investment and fixed operating costs associated with meeting that load. Efficient rate designs would reflect this cost to the maximum extent possible. If the rate design were not cost based, the usage component of the rate might be significantly greater, or significantly less than the cost the utility would incur to meet the increase in usage. If the rate were above the cost, customers would be charged amounts greater than the increase in cost incurred by the utility. If the rate were below cost, customers would pay less than the increase in cost, and would be encouraged to consume an excess amount. Thus, rate designs based upon cost are both fair, and efficient.

One obvious alternative to this problem would be to recover fixed costs through fixed charges commonly referred to as a straight fixed-variable rate design. From a pure economic perspective this type of rate design provides the most effective cost signals but such a method could result in very significant increases to smaller customers since they do not typically have demand meters that can be used to bill for the fixed charges. The BSA addresses this problem by essentially fixing the revenue requirement for each class. If average usage is greater than that in the test year, the BSA adjustment will reduce bills for all customers in that class. If it is less, it will increase delivery portion of the bill for customers, limited to the 10% cap. It does not penalize smaller customers or reward larger ones, but treats each customer in the class equally.

In conclusion, as part of its Blueprint for the Future filing and included in the Regulation Docket No. 59 proceeding, Delmarva has proposed a decoupling mechanism that is needed to be implemented as soon as possible to enable the Company and the state of Delaware to move forward. In developing the BSA, Delmarva went to great lengths to select the best program for Delaware. Delmarva's development of the BSA was the result of a careful review of the history of decoupling, the need to achieve successful reduction in load, the needs of Delaware customers, and problems posed by the present volumetric distribution rate designs. Delmarva's BSA was developed to benefit customers while removing the systematic conservation penalty that utilities currently face.

APPENDIX D
TRANSMISSION ANALYSIS

PJM has issued their recommendations for Transmission enhancements as it relates to the retirements of Indian River #1 and Indian River #2. The lists of reinforcements include:

Summer 2010

- Replace the Bethany 69kV capacitor bank with a two-staged 15 MVAR
- Replace Bethany T1 138/12kV transformer with a new 138/12kV unit
- Reconfigure the Wye Mills 138kV bus into a ring and add a 2nd 138/69kV transformer
- Replace the Wye Mills 69kV capacitor bank with a two-staged 15 MVAR
- Add a 2nd stage 8.4 MVAR capacitor at Grasonville 69kV
- Rebuild the Mt. Pleasant to Townsend 138kV line
- Rebuild the Trappe Tap to Todd 69kV line

Summer 2011

- Add a 3rd Indian River 230/138kV transformer

Beyond these generation retirements, we studied the effects of additional sensitivities if other units on the Delmarva Peninsula were to retire and the sequence of upgrades that will have to be built in order to be in compliance with strict reliability criteria for PJM.

The analysis is based on a DPL South load deliverability case for 2011. We added all approved RTEP projects out through summer 2011 and modeled the DPL South with higher imports due to the retirements of Indian River #1 and #2.

The study looked at an approach where other generating units will retire over time and what the system impacts will be on reliability.

Sensitivity 1 – Retirement of Vienna #8 and Vienna #10

The retirements of both Vienna generation units will result in two transmission lines to become contingency overloaded:

Overloaded Facility	Contingency Flow (MVA)	Base Flow (MVA)	Rating (MVA)	Loading (%)	Contingency
8818 GLASGOW 138 8827 MT PLSNT 138 1	***233.2***	82.4	232.0	***100.5***	Reybold - Lums Pond 138kV
9091 EASTN_69 69.0 9111 TRAPPETP 69.0 1	***117.3***	78.2	112.0	***104.7***	Vienna - Steele 230kV

Figure 1 – Thermal Overloads (Retirement of VN#8 and VN#10)

The plan would be to rebuild both circuits to obtain a higher ampacity.

Sensitivity 2 – Retirement of Vienna #8, Vienna #10, Edge Moor #3, and Edge Moor #4

In addition to the results of Sensitivity #1, the added retirements of the two Edge Moor units will require adding more reactive capability in the DPL South zone in order to improve the voltage profile for the contingency loss of the Red Lion to Cedar Creek 230kV line:

Ncon	Contingency	Contingency Name	#Viols	LFStatus
18	Ckt 23030	Red Lion - Cedar Creek 230kV	181	Non-Convergent

The plan would require the addition of two transmission capacitors to boost the voltages in the Bay Region.

Sensitivity 3 – Retirement of Vienna #8, Vienna #10, Edge Moor #3, Edge Moor #4, Indian River #3, and Indian River #4

The result of losing this much generation on the Delmarva Peninsula will trigger the need to build additional transmission facilities. There are multiple transmission contingencies that would cause voltage violations all across the Bay region.

Ncon	Contingency	Contingency Name	#Viols	LFStatus
1	Ckt 5015	Red Lion - Hope Creek 500kV	124	Non-Convergent
9	Ckt 23001	Keeney - Steele #1 230kV	177	Non-Convergent
11	Ckt 23009	Keeney - Steele #2 230kV	175	Non-Convergent
18	Ckt 23030	Red Lion - Cedar Creek 230kV	225	Non-Convergent
19	Ckt 23031	Cedar Creek - Milford 230kV	214	Non-Convergent
20	Ckt 23032	Red Lion - Cartanza 230kV	216	Non-Convergent
21	Ckt 23033	Cartanza - Milford 230kV	177	Non-Convergent
22	Ckt 23034	Milford - Indian River #2 230kV	178	Non-Convergent
24	Ckt 23069B	Milford - Indian River #1 230kV	178	Non-Convergent
26	Ckt 23085	Vienna - Steele 230kV	202	Non-Convergent
63	Ckt 13808	Mt. Pleasant - Townsend 138kV	169	Non-Convergent
83	Ckt 13833	Townsend - Church 138kV	168	Non-Convergent
147	Cool Springs AT20	Cool Springs 230/69kV	177	Non-Convergent
156	CedarCk AT20	Cedar Creek 230/138kV	179	Non-Convergent
196	Nelson SVC	Nelson SVC 150 MVAR	176	Non-Convergent
197	IR SVC	Indian River SVC 150 MVAR	175	Non-Convergent

The most cost effective long-term solution would be to build out the 230kV facilities in the Vienna area which solves the contingency problems.

APPENDIX E

(Separate Attachment-Letter from PJM, dated February 28, 2008)